Clean Energy States Alliance

Offshore Wind to Green Hydrogen

INSIGHTS FROM EUROPE

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ABOUT THIS REPORT

This report prepared by the Clean Energy States Alliance (CESA) covers the plans, strategies, proposals, and challenges for the development of green hydrogen from offshore wind generation in Europe. It describes the current policy drivers facilitating its development, as well as potential future support mechanisms, value streams, and market barriers. In addition, it examines the cost, safety, and emissions impacts of using green hydrogen natural gas admixtures for power generation. The report concludes with implications for the US and proposes that the federal government and states pursue steps to ensure that any future green hydrogen use does not negatively impact frontline communities. Four case studies on hydrogen strategies and demonstration projects in Europe are included in the Appendix.

ABOUT THE AUTHOR

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EXECUTIVE SUMMARY

Europe has been giving considerable attention to "green hydrogen" as part of increasing efforts to achieve the continent's greenhouse gas reduction goals and especially to overcome the challenge of decarbonizing hard-to-electrify sectors. "Green hydrogen" refers to hydrogen that has been produced from clean renewable energy using electrolysis, as opposed to "grey hydrogen," which is mostly industrially produced from natural gas, or other forms of hydrogen between green and grey.

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Hydrogen (H2) is currently used in Europe in limited quantities, and it is mostly grey hydrogen. To scale up green hydrogen, the European Union (EU) and individual European countries are investing in important infrastructure elements such as electrolyzers (systems that uses electricity to break water into hydrogen and oxygen), pipelines, and refueling stations, as well as in innovation, research and development, and demonstration projects. They are also developing regulatory frameworks designed to support the green hydrogen economy.

POWER-TO-X

Power-to-X (PtX) is an umbrella term, primarily used in Europe, for the conversion of electricity into other energy forms such as synthetic fuels (liquids or gas) or heat. PtX is being explored in Europe especially for offshore wind. Arguments for PtX include:

- The conversion of electricity into hydrogen can allow difficult-to-electrify sectors to transition to carbon-free energy.
- PtX can reduce curtailments if excess offshore wind output is transformed into hydrogen.
- PtX enables flexible demand and confers grid benefits.

THE RATIONALE FOR OFFSHORE WIND TO GREEN HYDROGEN

With many offshore windfarms already installed and even more being planned, offshore wind is likely to play an important role in the production of hydrogen in

Europe. Reasons why European governments and industry are focusing on offshore wind when looking to ramp up hydrogen production include:

- The next phase of offshore wind projects will include extra-large 12+ megawatt (MW) turbines and have more capacity than ever before.
- Many of the next generation offshore wind projects will face long distances to shore, limited interconnection points, and projected grid constraints; they may therefore be well suited for dedicated hydrogen production or for converting excess capacity to hydrogen.
- Offshore wind has a higher capacity factor than other renewables, meaning an electrolyzer can operate for a greater proportion of time and produce more hydrogen.
- The ability to interconnect multiple projects could enable multi-gigawatt (GW) offshore hydrogen production hubs.
- Many of the potential end uses of hydrogen, such as in refinineries, the metal industry, marine transport, and export/import facilities are located on the coast, near to offshore windfarm locations.

Offshore wind has a higher capacity factor than other renewables, meaning an electrolyzer can operate for a greater proportion of time and produce more hydrogen.

There are also drawbacks to using offshore wind to produce hydrogen, especially the fact that offshore wind has a higher levelized cost of electricity (LCOE) than solar PV and onshore wind.

OFFSHORE WIND TO HYDROGEN CONCEPTS

Several different Offshore Wind-to-Hydrogen concepts are being considered in Europe. They fall into the following categories:

- An offshore windfarm connected to onshore hydrogen production via a direct physical connection
- An offshore windfarm connected to onshore hydrogen production via a power purchase agreement (PPA)
- An offshore windfarm with offshore on-turbine hydrogen production
- An offshore windfarm with hydrogen production at a central offshore hydrogen production platform; this concept is particularly relevant for windfarms far from shore.

POSSIBLE USES OF GREEN HYDROGEN

Hard-to-electrify sectors are the high-impact end-use applications for hydrogen and PtX fuels. Green hydrogen could be used in the following applications compatible with decarbonization:

- Fuel for heavy-duty transportation—long-distance trucking, shipping, aviation, and material-handling vehicles.
- Industrial clusters—hydrogen could play a role in the refining industry, the chemical industry, and the metallurgical industry.
- Energy storage—stored compressed hydrogen can be used in fuel cells to provide power on demand; if enough hydrogen is stored on site, fuel cells can provide long duration storage.
- Combined heat and power (CHP) systems—stationary fuel cells can provide both heat and power.
- Stationary power—stationary fuel cells can be stacked to produce electricity for primary power generation at the building or micro-grid level.

Power generation represents a lower priority use of hydrogen because it can lead to higher nitrogen oxide (NOx) emissions and can extend the use of power plants fueled by natural gas, preventing their replacement with cleaner technologies.

CHALLENGES TO LARGE-SCALE GREEN HYDROGEN PRODUCTION

Several technical and financial challenges stand in the way of bringing green hydrogen to full commercial scale in Europe. These include the following:

The biggest barrier to widespread green hydrogen adoption is the high cost of producing hydrogen compared to fossil fuel equivalents.

- The limited availability and high cost of electrolyzers
- The high cost of renewable electricity compared to natural gas
- The high costs of hydrogen storage and transportation
- The need for either a very large fresh water supply or desalination of seawater for electrolysis
- Limited policies and regulatory mechanisms that support green hydrogen market development and infrastructure buildout.

The biggest barrier to widespread green hydrogen adoption is the high cost of producing hydrogen compared to fossil-fuel equivalents. Grey hydrogen produced from natural gas without carbon capture is the cheapest form of hydrogen production, although that price does not include any consideration of costs associated with carbon emissions. The cost of green hydrogen from offshore wind is projected to come down significantly by 2030, but it would still be more expensive than hydrogen produced from fossil fuels without a carbon price.

IMPLICATIONS FOR THE UNITED STATES

It may ultimately make sense to use some of the offshore wind output in the United States for green hydrogen production. However, offshore wind in the US is at a much earlier stage of development than offshore wind in Europe. For at least the next decade, the output from US wind farms will be fully needed for electricity production that displaces fossil-fuel generation. That electricity will be especially valuable because the wind farms will be relatively close to major load centers.

Nevertheless, the US federal government and the states should not ignore green hydrogen. They might consider the following steps:

- Pursue research into hydrogen technologies and applications, especially to ensure that any future expanded hydrogen use does not cause unforeseen environmental, social, or economic problems.
- Research whether there is likely to be excess offshore wind output sometime after 2030 and whether it could be cost-effectively used to produce green hydrogen.
- Prepare roadmaps for green hydrogen development, including electrolyzer and fuel cell targets.
- Enter into partnerships between states and the US Department of Energy or its national laboratories to study potential hydrogen applications and technologies; research partnerships might focus on improved electrolyzer efficiencies, safe hydrogen transportation and storage, and potential applications across a variety of sectors.
- Support some well-chosen green hydrogen pilot projects.
- Continue to monitor policy development, hydrogen strategies, and the green hydrogen market in Europe.

It will be imperative for states to engage stakeholders, including environmental justice and community-based organizations, in dialogue and discussion on green hydrogen's production, potential applications, and pathways. Stakeholder engagement should occur prior to any decisions on demonstration projects or publication of roadmaps.

Finally, states and the federal government should resist efforts by fossil fuel companies and utilities to use the long-term vision of a hydrogen future as a rationale for building more natural gas generators and perpetuating existing fossil fuel technologies.

States and the federal government should resist efforts by fossil fuel companies and utilities to use the long-term vision of a hydrogen future as a rationale for building more natural gas generators and perpetuating existing fossil fuel technologies.

This report looks at plans, prospects, and challenges for offshore wind energy to produce green hydrogen in Europe. It covers the current policy drivers facilitating its development, as well as possible future support mechanisms. It examines the proposed alternative possible uses of hydrogen, market barriers, and value streams. It also describes current and projected costs, as well as the current and projected future state of green hydrogen technology. It looks at the debate over whether to inject hydrogen as a blend in natural gas pipelines and considers the cost, safety, and air pollution implications of different blending possibilities. Finally, it includes an Appendix with four extended case studies:

- The European Union's Hydrogen Strategy
- Denmark's Offshore Wind to Hydrogen Proposition
- Hydrogen for Germany's Energy Transition
- Green Hydrogen Demonstration Projects Underway in the United Kingdom (UK).

INTRODUCTION

Many visions of a carbon-free clean energy future rest on the electrification of nearly everything, with combustion technologies becoming anachronistic. To complement electrification, some energy planners and developers are eyeing and promoting green hydrogen as an important component of these clean energy visions. They envision hydrogen as a clean fuel and energy carrier that can decarbonize a wide range of hard-to-electrify sectors and industries and support the growth of renewables.

"Green hydrogen" is hydrogen that has been produced from clean renewable energy. It is the zero-carbon, climate-friendly cousin of "grey hydrogen," which is mostly industrially produced from natural gas and of "blue hydrogen," a version of grey hydrogen where the carbon emissions are captured and stored.[1] Some researchers and advocates have proposed green hydrogen as a desirable complement to offshore wind development. In addition to its applicability in a range of end-use applications, green hydrogen has the ability to serve as a grid-scale energy storage solution, potentially offering reliability, flexibility, and stability benefits.

This report focuses on Europe's approach to green hydrogen development and unpacks the opportunities and barriers to its roll out. Abundant offshore wind capacity, European climate policy, and carbon prices have driven interest in green hydrogen. Significant pilot projects are already underway throughout Europe. Governments there are looking across sectors for carbon-reduction opportunities and view green hydrogen as a necessary technology for economy-wide decarbonization. The European Union (EU) Hydrogen Strategy and several European national strategies place green hydrogen and its refined products (e.g., ammonia, methanol, synthetic kerosene) on center stage as critical fuels for reducing carbon emissions.[2] The EU Hydrogen Strategy is divided into three phases, each with specific objectives and targets that impact a range of sectors such as heavy transport, industry, and energy storage.

This report focuses on Europe's approach to green hydrogen development and unpacks the opportunities and barriers to its roll out.

For example, Spain's recent hydrogen roadmap (released in October 2020) outlines green hydrogen's role in transportation, industry, and storage. The Spanish government

1 In fact, there is an entire rainbow of hydrogen types including turquoise and brown hydrogen. In this paper, we only discuss grey, blue, and green hydrogen.

2 European Commission, July 2020.

has announced that it will invest billions of euros (€) into green hydrogen infrastructure over the next decade to replace the grey hydrogen currently consumed by industry and for use in transportation (fuel cell buses, light and heavy-duty freight, and public hydrogen refueling stations). The country aims to install 4 GW of electrolyzers by 2030 for the production of green hydrogen to decarbonize hard-to-electrify-sectors and to use for energy storage. Spain is identifying important hydrogen-consumption clusters and designing financial instruments to support hydrogen infrastructure and industries. It is also developing incentive mechanisms for transportation fuel cells and synthetic fuels.[3]

EU member states plan to use much of offshore wind's output to produce green hydrogen. Seventy (70) GW of offshore wind projects are scheduled to come online by 2028 and 300+ GW are projected by 2050 in Europe alone. The impetus for pairing hydrogen with offshore wind includes offshore wind's large scale, significant expansion opportunities, high-capacity factors, and rapidly declining costs. The cost of offshore wind has fallen by 46 percent since 2015, and costs continue to decline.[4] As future offshore wind projects off the coast of Europe get pushed farther from the coast, some experts believe it will be cheaper to produce hydrogen out at sea and build dedicated pipelines to shore rather than to lay high-voltage direct current (HVDC) cables to bring electricity to land.

CHALLENGES FACING EUROPE'S TRANSITION TO LARGE-SCALE USE OF GREEN HYDROGEN

Several technical and financial challenges stand in the way of bringing green hydrogen to full commercial scale in Europe. These include: 1) the limited availability and high cost of electrolyzers; 2) the high cost of renewable electricity compared to natural gas; 3) the high costs of hydrogen storage and transportation; and 4) a limited number of policies and regulatory mechanisms that support green hydrogen market development and infrastructure buildout.

As green hydrogen moves towards commercialization, it is important to consider hydrogen's environmental and health impacts.

Additionally, as green hydrogen moves towards commercialization, it is important to consider hydrogen's environmental and health impacts. For example, the combustion of hydrogen and hydrogen-gas blends can result in higher nitrogen oxide (NOx) emissions, which can pose serious public health damage. NOx is a highly reactive compound that reacts in the atmosphere to form ozone and contribute to acid rain.[5] Hydrogen-natural gas blends could extend the

3 David Diez and Alejandro Martinez, "The Spanish Hydrogen Strategy," *Watson Farley & Williams*, March 30, 2021. https://www.wfw.com/articles/the-spanish-hydrogen-strategy, (accessed August 30, 2021).

4 BVG Associates data.

5 U.S. Environmental Protection Agency, "Technical Bulletin: Nitrogen Oxides (NOx), Why and How They Are Controlled," *Clean Air Technology Center,* November 1999, https://www3.epa.gov/ttn/catc/dir1/fnoxdoc.pdf, (accessed August 30, 2021).

life of natural gas infrastructure, making it more difficult to phase out natural gas and prolonging the environmental and public health impacts associated with power plant emissions.

IMPLICATIONS FOR THE UNITED STATES

For the United States, it will be important to move forward carefully and deliberately, with appropriate policies and precautions in place. The US offshore wind industry is at a much earlier stage of development than the European industry, so the use of offshore wind output for large-scale hydrogen production should be on a much slower trajectory than in Europe. For at least the next decade, the output from the initial US wind farms will be fully needed for electricity production that displaces fossil fuel generation. The offshore wind generation that results from the first phase of offshore wind development in the US will be especially valuable as it will be delivered close to load centers in areas with few renewable alternatives.

The US can use learnings from the European experience and from European plans to ensure that green hydrogen is developed here only in ways that will assuredly lower carbon dioxide (CO_2) and NOx emissions, be used in highest-value end-use applications, and advance equity. It will also be important to ensure that the vision of a green hydrogen future is not used to extend the life of polluting power plants.[6]

In the following sections in this report, we focus on the development of green hydrogen in Europe, including the relationship between offshore wind and hydrogen, the policy drivers and support mechanisms facilitating its development, key enablers and market barriers, value streams, and potential next steps for US states interested in considering green hydrogen in their clean energy portfolios.

6 For a critique of the argument that hydrogen's future potential justifies continued use of fossil fuel generators, see: Lew Milford, Seth Mullendore and Abbe Ramanan, "Hydrogen Hype in the Air," *Clean Energy Group*, December 14, 2020, https://www.cleanegroup.org/hydrogen-hype-in-the-air, (accessed August 30, 2021).

SECTION ONE

POWER-TO-X: OVERVIEW OF TECHNOLOGY, COSTS, AND APPLICATIONS

Clean electricity can decarbonize much of the energy system through the electrification of buildings, industry, and transportation. Although the upper limit of electrification is subject to change as technology innovation improves, some experts estimate that electricity can only meet 70 percent of total energy demand.[7] Given that some share of energy demand cannot be electrified, there will be some remaining sectors that need alternative fuels. These will include heavy-duty transportation, industrial processes like steel manufacturing, and air and marine transport.[8] They will require strategies other than electrification and are likely to rely on Power-to-X (PtX).[9]

Power-to-X is an umbrella term for the conversion of electricity into other energy forms such as synthetic fuels (liquids or gas) or heat. It is largely a European term coined to reference the integration of green fuels produced indirectly by electrification, thus combining two distinct energy sectors (referred to in Europe as energy sector coupling) and bringing joint value to existing electric and gas infrastructure. Sector coupling relies on excess or curtailed wind and solar (or future purpose-built renewable energy projects) for PtX. Offshore wind will likely play a major role in the future development of PtX in Europe.

Offshore wind will likely play a major role in the future development of PtX in Europe.

Power-to-X for use in different end-use applications like heating, transportation, and heavy industry is already underway in Europe, driven by climate directives, abundant renewable resources, anticipated demand, and hydrogen roadmaps. While hydrogen can be produced from oil, coal, and natural gas, these fossil fuels yield grey hydrogen, whereas green hydrogen is produced from water through electrolysis powered by green electricity.[10] Electrolysis splits water into hydrogen and oxygen, and when the

7 International Renewable Energy Agency, "Global Energy Transformation: A roadmap to 2050," *irena.org*, 2018, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Apr/IRENA_Report_GET_2018.pdf, (accessed August 19, 2021).

8 One of the potential pathways to decarbonizing the steel industry is to increase steel recycling. This process requires lower temperatures than manufacturing steel from raw iron ore and may be possible to manufacture with electric arc furnaces. See: Christian Hoffman et al. "Decarbonization challenge for steel," *McKinsey&Company*, June 30, 2020, https://www.mckinsey.com/industries/metals-and-mining/our-insights/decarbonization-challenge-for-steel, (accessed August 19, 2021).

9 Electrification is suitable for processes requiring relatively low heat, such as space heating and cooling, which comprise around 13 percent of industrial heat requirements. See: Tobias Fleite et al, "Mapping and analyses of the current and future (2020–2030) heating/cooling fuel deployment (fossil/renewables)," *European Commission*, September 2016, https://ec.europa.eu/energy/sites/ener/files/documents/mapping-hc-final_report_wp1.pdf, (accessed August 19, 2021).

electricity used to drive the electrolysis is renewable, the resulting hydrogen is "green" and yields zero emissions.[11] The resulting green hydrogen can be further processed to produce renewable gas, synthetic fuels, and chemicals—these are the "X" in PtX, namely methane, methanol, ammonia and other liquid electrofuels (e-fuels), which result from green hydrogen reacted with carbon dioxide.[12] In this report, we focus on green hydrogen produced with renewable electricity provided by offshore wind projects. This conversion of power to gas (hydrogen, in this case) is referred to as PtG.

Green hydrogen and hydrogen-based synthetic fuels and chemicals can be used in a variety of applications. Applications that are compatible with decarbonization include:

- Fuel for heavy-duty transportation—long-distance trucking, shipping, trains, aviation, and material-handling vehicles (e.g., forklifts) could run on fuel cells fueled by hydrogen.
- Industrial clusters—hydrogen could play a role in the refining industry, the chemical industry, and the metallurgical industry.[13]
- Energy storage—stored compressed hydrogen can be used in fuel cells to provide power on demand. If enough hydrogen is stored on site, fuel cells can provide long-duration storage (e.g., over days, weeks, and longer). If electrolyzers are located on-site, they can provide continuous hydrogen for the fuel cells, lengthening the storage duration.
- Combined heat and power (CHP) systems—stationary fuel cells in CHP systems are over 80 percent efficient and can provide both heat and power.
- Stationary power—stationary fuel cells can be stacked to produce electricity for primary power generation at the building or micro-grid level.

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Power generation represents a lower priority use of hydrogen, because it can lead to higher NOx emissions (if the hydrogen is combusted) and can be used by natural gas power plant owners to justify extending the life of those plants, rather than replacing them with cleaner technologies like renewables. Nevertheless, hydro-

10 There are many hydrogen production processes using different energy sources. The most common production method is through steam methane reformation, splitting gas into hydrogen and water and releasing CO_2 emissions. This process yields grey hydrogen. There is also "blue" hydrogen, which is grey hydrogen but with its carbon emissions captured and stored.

11 While the production of green hydrogen does not produce emissions, hydrogen's end use can still result in harmful emissions. In addition, electrolysis is a water-intense process, requiring up to 9 tons of purified water to yield one ton of hydrogen.

12 International Renewable Energy Agency, "Innovation Landscape for a Renewable-Powered Future: Solutions to Integrate Variable Renewables," *irena.org*, 2019, https://irena.org/-/media/Files/IRENA/Agency/Topics/Innovation-and-Technology/IRENA_Landscape_Solution_11.pdf?la=en&hash=2BE79AC597ED18A96E5415942E0B93232F82FD85, (accessed August 20, 2021).

13 In the refining industry, green hydrogen can be used to remove impurities from crude oil; in the chemical industry, green hydrogen can be used as the feedstock for the production of methanol, ammonia, fertilizers, and biofuels; in the metallurgical industry, green hydrogen can be used as a high heat source in furnaces or can act as a reducing agent for metal alloys.

gen or hydrogen-natural gas blends can be injected into hydrogen or natural gas pipelines and burned in power plants. Burning this blended fuel may results in lower carbon emissions, but it will produce higher NOx emissions when combusted in almost all existing gas turbines.[14]

There are other challenges associated with hydrogen-natural gas blending. According to the International Energy Agency (IEA), hydrogen can be blended up to approximately 20 percent with natural gas before it begins embrittling metal in pipelines or negatively affecting end-use appliances.[15] Higher concentrations may be possible with upgrades to natural gas infrastructure and various research studies and pilot projects are testing higher admixtures. Currently there is no consensus or standard in Europe on the allowable blending rate, and countries permit different admixture percentages. Some EU member states prohibit altogether the injection of hydrogen into the natural gas pipeline network.[16]

There are advantages to converting green hydrogen to green synthetic fuels like methane, methanol, and ammonia. They can be produced directly at the site of hydrogen production with the addition of carbon (for methane and methanol) and nitrogen (for ammonia), have existing global demand, and are easier to transport and store as fuels. Methane and ammonia can be used as direct replacements for their fossil-fuel counterparts. Some aviation and shipping companies are planning to decarbonize their fleets with these renewable alternative fuels.[17] In addition, methanol and ammonia can be used as chemical feedstocks, and ammonia can be used as a fertilizer. Because ammonia is easier and cheaper to transport than hydrogen, ammonia confers the additional advantage of being able to be converted back to hydrogen at the point of need, although this conversion is both energy intensive and costly.

How Fuel Cells Use Hydrogen to Generate Electricity

Fuel cells produce electricity through an electrochemical reaction combining oxygen and hydrogen. Fuel cells can run on hydrogen and other PtX fuels such as ammonia and methanol. Fuel cells are comprised of an electrolyte sandwiched between two electrodes. Hydrogen is pushed through a negative electrode (anode) where the molecules are split into protons and electrons. The protons travel to a positive electrode (cathode), where they combine with air (oxygen) and produce water and heat. The electrons travel through an external circuit, where they create electricity (see the US DOE Hydrogen and Fuel Cells Technologies website at www.energy.gov/eere/fuelcells/fuel-cells). As long as hydrogen and oxygen are supplied as "fuel," the fuel cell can run indefinitely.

14 Manufacturers are developing specialized gas turbines that can burn higher concentrations of hydrogen with reduced NOx emissions, see Sonal Patel, "High-Volume Hydrogen Gas Turbines Take Shape," *Power*, May 1, 2109, https://www.powermag.com/high-volume-hydrogen-gas-turbines-take-shape, (accessed August 20, 2021).

15 "The Future of Hydrogen: Seizing today's opportunities," *International Energy Agency*, June 2019, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf, (accessed August 20, 2021).

16 "Hydrogen Europe Vision on the Role of Hydrogen and Gas Infrastructure on the Road Toward a Climate Neutral Economy," *Hydrogen Europe Secretariat*, April 2019, https://ec.europa.eu/info/sites/info/files/hydrogen_europe_-_vision_on_the_role_of_hydrogen_and_gas_infrastructure.pdf, (accessed August 20, 2021). See page 14 for details.

17 For example, Maersk, the world's largest container shipping company, announced in 2018 that it would fully decarbonize its operations and its supply chains by 2050.

COSTS OF PRODUCTION, WATER, STORAGE, TRANSPORT

High costs represent green hydrogen's biggest challenge. Hydrogen is expensive to produce, store, and transport. Europe is engaged in studying and implementing safety and technical standards for the production, storage, and transport of hydrogen. The solutions and stan-dardizations will have an impact on costs.

High costs represent green hydrogen's biggest challenge. Hydrogen is expensive to produce, store, and transport

Production

The cost of hydrogen production depends not only on the cost of renewable electricity, but also on the capital and operating costs of electrolyzers. Global hydrogen production capacity is limited by the number of available electrolyzers. Until electrolyzer production scales up, capacity will remain limited and costly.[18] Europe's electrolyzer capacity should reach 40 GW by 2030 based on country targets and industry plans, and another 40 GW of capacity targeted from imports.[19] Japan and Spain, for example, have targets in place to make hydrogen more cost competitive by supporting electrolyzer production. Europe has a strong electrolyzer manufacturing market, but capital costs are predicted to remain high until industrial scale-up brings costs down.[20] The cost of renewable electricity is expected to decrease as more offshore wind comes online across Europe, and this decrease should lower the cost of green hydrogen production. With offshore wind's massive scale-up, BVG Associates estimates that the cost of green hydrogen from offshore wind will be approximately €2 ($3.50/kilogram [kg]) by 2030, according to various sources including the Hydrogen Council, a global CEO-led initiative that envisions hydrogen playing a major role in the clean energy transition.[21] The International Energy Agency (IEA) estimates that the global price of green hydrogen will decrease to €1.10–2.40/kg (US$1.31–2.85/kg) by 2030 and BNEF forecasts that by 2050 green hydrogen will have fallen by 85 percent to €0.85/kg (USD $1.00/kg) and will be on par with grey hydrogen costs.[22] US Department

18 Noé van Hulst, "The clean hydrogen future has already begun," *International Energy Agency*, April 23, 2019, https://www.iea.org/commentaries/the-clean-hydrogen-future-has-already-begun, (accessed August 19, 2021).

19 40 GW are expected to be deployed in Europe and an additional 40 GW will be exported to the EU from neighboring countries. See: "A hydrogen strategy for a climate-neutral Europe," *Communication from The Commission to The European Parliament, The Council, The European Economic and Social Committee and The Committee of The Regions*, August 7, 2020, https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf, (accessed August 19, 2021).

20 "Hydrogen Europe Vision on the Role of Hydrogen and Gas Infrastructure on the Road Toward a Climate Neutral Economy," *Hydrogen Europe Secretariat*, April 2019, https://ec.europa.eu/info/sites/info/files/hydrogen_europe_-_vision_on_the_role_of_hydrogen_and_gas_infrastructure.pdf, (accessed August 20, 2021).

21 Leigh Collins, "Green hydrogen 'cheaper than unabated fossil-fuel H2 by 2030': Hydrogen Council," *Recharge*, January 21, 2020, https://www.rechargenews.com/transition/green-hydrogen-cheaper-than-unabated-fossil-fuel-h2-by-2030-hydrogen-council/2-1-741658, (accessed August 20, 2021).

22 "A hydrogen strategy for a climate-neutral Europe," *Communication from The Commission to The European Parliament, The Council, The European Economic and Social Committee and The Committee of The Regions*, August 7, 2020, https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf, (accessed August 20, 2021) and "Hydrogen Economy Outlook," *BloombergNEF*, March 30, 2020, https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf, accessed August 20, 2021). This estimate for green hydrogen is from a range of renewables, including less-expensive solar.

of Energy cost projections for hydrogen from low-cost renewables such as solar and wind indicate costs at less than \$2.00/kg by 2035.[23] To verify green hydrogen's renewable origin, a certificate or guarantee of origin system for green hydrogen will need to be developed across Europe to allow the production of renewable hydrogen to be tracked and to appropriate price signals.

Water

Producing hydrogen through electrolysis requires large amounts of water—up to nine tons of water for one ton of hydrogen produced. This is a significant concern—and cost—for electrolysis in drought-prone areas and where freshwater is in short supply.[24]

To avoid this problem, offshore wind developers have proposed producing hydrogen offshore and on-turbine with desalinized water.[25] However, desalination adds one more step to the process of producing green hydrogen, with negligible increases in cost.[26]

Various research studies are underway analyzing seawater's potential in electrolysis. Harvard University researchers have found that forward osmosis could be effective in splitting water for hydrogen. And a US National Science Foundation-funded team has analyzed the cost implications of seawater reverse osmosis and has found that it would result in only a small increase in the levelized cost of hydrogen (LCOH).[27] Another sea water reverse osmosis study by researchers at the University of Calgary concluded that desalination could potentially result in only small increases to LCOH. The researchers concluded that the capital and operating costs of sea water reverse osmosis on LCOH would be less than \$0.10/kgH2.[28]

Storage

Unless hydrogen is produced at or near the site of its end use, it needs special storage and transportation infrastructure, or it needs to be further refined before distribution. Hydrogen storage infrastructure should be located as close as possible to its end-use application (e.g., at an industrial hub) to minimize costs and so that

23 "Department of Energy Hydrogen Program Plan," *US Department of Energy*, November 2020, https://www.hydrogen.energy.gov/pdfs/hydrogen-program-plan-2020.pdf, (accessed August 21, 2021) and DOE Hydrogen and Fuel Cells Program Record: Record 19009: "Hydrogen Production Cost From PEM Electrolysis – 2019," *U.S. Department of Energy*, February 3, 2020, https://www.hydrogen.energy.gov/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf, (accessed August 20, 2021).

24 Rebecca R. Beswick, Alexandra M. Oliveira, and Yushan Yan, "Does Green Hydrogen Have a Water Problem?" *ACS Energy Letters* 0, 6; DOI:0.1021/acsenergylett.1c01375, https://pubs.acs.org/doi/pdf/10.1021/acsenergylett.1c01375, (accessed August 30, 2021).

25 On-turbine refers to an electrolyzer located on the offshore wind turbine platform itself.

26 Desalination through reverse osmosis would add no more than \$0.01 per kilogram of hydrogen. Ibid, Beswick, Oliveria and Yan, https://pubs.acs.org/doi/pdf/10.1021/acsenergylett.1c01375, (accessed August 30, 2021).

27 NSF Public Affairs, "Generating renewable hydrogen fuel from the sea," *National Science Foundation*, October 6, 2020, https://www.nsf.gov/discoveries/disc_summ.jsp?cntn_id=301369&org=NSF&from=news, (accessed August 22, 2021).

28 M.A. Kahn et al, "Perspective Seawater Electrolysis for Hydrogen Production: A Solution Looking for a Problem?" March 8, 2021, https://chemrxiv.org/engage/api-gateway/chemrxiv/assets/orp/resource/item/60c755dabb8c1a9e473dc4ca/original/seawater-electrolysis-for-hydrogen-production-a-solution-looking-for-a-problem.pdf, (accessed August 22, 2021).

the hydrogen can be used as is (rather than as a further-refined e-fuel). In addition, onsite large-scale hydrogen storage can enable the development of hydrogen-based industrial and processing clusters.

For storage aboard ships and planes, hydrogen could be converted into ammonia, methanol, or synthetic kerosene, and then used as a drop-in fuel.

Hydrogen is expensive to store, especially in small volumes. It is a highly reactive gas requiring storage at high pressure (10,000 pounds per square in gauge [psig]) as compressed gas or at very low temperatures as cryogenic liquid.[29] High-pressure storage compresses hydrogen, which has low energy content by volume, so that quantities of hydrogen can be stored without taking up large amounts of space. Large-scale compressed gas storage in natural underground caverns (e.g., salt caverns), in modified natural gas storage systems, and in dedicated hydrogen pipelines are more cost effective than storing small volumes of hydrogen.[30]

For storage aboard ships and planes, hydrogen could be converted into ammonia, methanol, or synthetic kerosene, and then used as a drop-in fuel. These fuels are more energy dense than hydrogen and would thus take up less cargo space on board. They do not need to be stored at high pressure like hydrogen.[31]

Distribution

Hydrogen can be transported long distances via pipelines or in special containers by rail, ship, or semi-truck. Hydrogen and hydrogen blends require special or retrofitted natural gas pipelines for transport due to potential embrittlement concerns. Hydrogen embrittlement can theoretically occur if monatomic hydrogen diffuses into preexisting cracks or fractures and accelerates their propagation. However, unless the internal pressure within the pipeline fluctuates in a pipeline with pre-existing cracks in the presence of monatomic hydrogen, hydrogen embrittlement appears unlikely at low hydrogen blends.[32] Potential hydrogen embrittlement and corrosion is more likely to

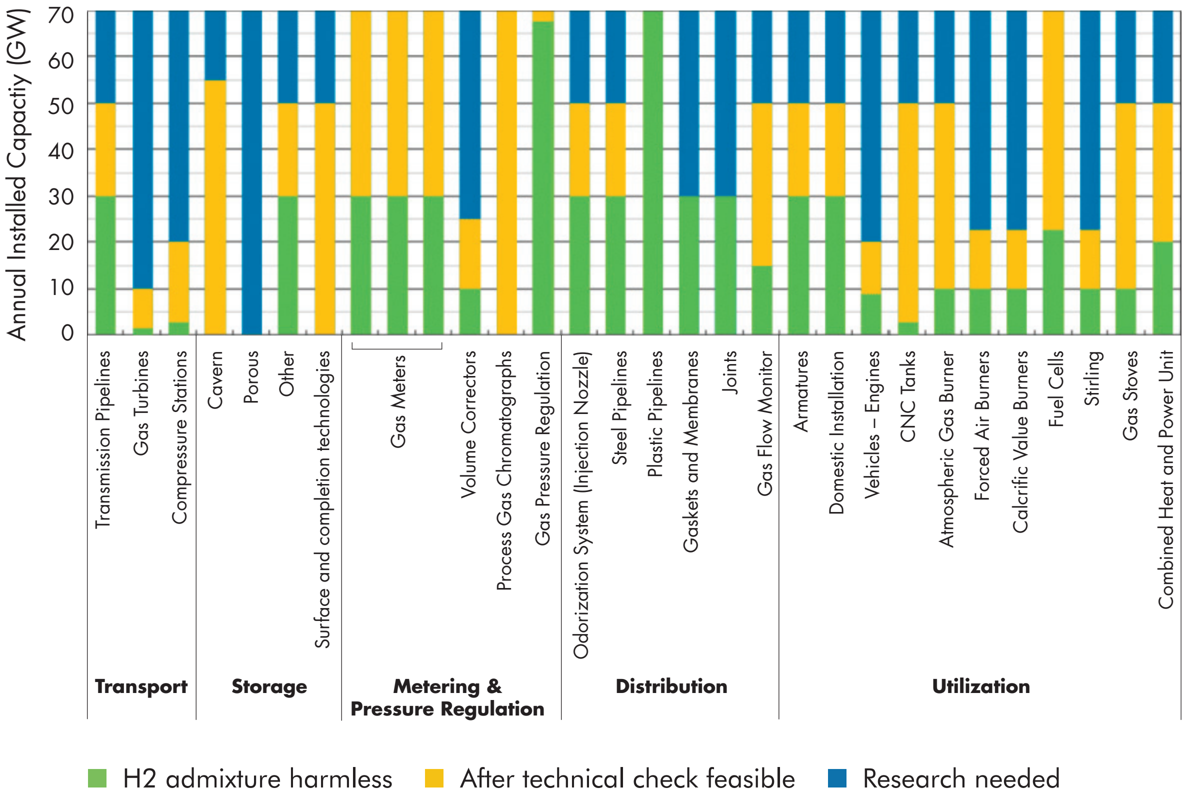
29 Kelvin Mahal, "The Emerging Hydrogen Economy," *Akin Gump Strauss Hauer & Feld LLP*, December 18, 2019, https://www.akingump.com/en/experience/industries/energy/speaking-energy/the-emerging-hydrogen-economy.html (accessed August 22, 2021).

30 For technical information on salt cavern storage, see: Emiliano Bellini, "Hydrogen storage in salt caverns," *PV Magazine*, June 16, 2020, https://www.pv-magazine.com/2020/06/16/hydrogen-storage-in-salt-caverns (accessed August 22, 2021) and for cost implications see: "Technology Roadmap: Hydrogen and Fuel Cells," *International Energy Agency*, 2015, https://www.iea.org/reports/technology-roadmap-hydrogen-and-fuel-cells, (accessed September 7, 2021).

31 Hydrogen also can be stored on ships and used in fuel cells, but H2 storage would take up significant space onboard.

32 There are many theories on the mechanism of hydrogen embrittlement; however, consensus among researchers has not been established. The intrinsic effect of hydrogen in metal on fatigue crack behavior has not yet been directly observed. Most hydrogen embrittlement has been simulated in lab research; see Yukitaka Murakami, "Hydrogen embrittlement," *Metal Fatigue* (Second Edition), 2019, https://www.sciencedirect.com/topics/engineering/hydrogen-embrittlement, (accessed August 23, 2021). Lower strength steel is more resistant to hydrogen embrittlement, but it can be damaged by hydrogen in a way that leads to pipeline failure rather than a catastrophic fracture. There are three critical factors that would lead to hydrogen embrittlement of steel pipelines: fluctuating internal pressure, monatomic hydrogen, and the integrity of the steel and any pre-existing fractures. Pure hydrogen in pre-existing natural gas pipelines would require substantial modifications to account for potential hydrogen embrittlement; see: "Hydrogen Transportation Pipelines," *European Industrial Gases Association*, 2004, https://h2tools.org/sites/default/files/Doc121_04%20H2TransportationPipelines.pdf, (accessed August 23, 2021).

FIGURE 1: **Current H2 admixture limits by volume on gas infrastructure components**



Source: Taibi, Emanuele & Miranda, Raul & Vanhoudt, Wouter & Winkel, Thomas & Lanoix, Jean-Christophe & Barth, Frederic. (2018). Hydrogen from renewable power: Technology outlook for the energy transition.

occur with higher hydrogen concentrations. It is generally believed that natural gas admixtures containing more than 20 percent hydrogen require pipeline retrofitting so that the hydrogen does not embrittle the pipeline steel. However, the pipeline's ability to accept higher admixtures depends on the type of steel in the pipeline, the purity of the hydrogen, and the entire distribution system.[33] See **Figure 1**.

Natural gas is transmitted inter-Europe through transmission pipelines, generally constructed of carbon steel material and covered with a specialized coating to prevent corrosion. They are generally high-pressure pipelines, transporting gas between 500–1,000 psig.[34] Distribution pipelines transport gas at lower pressures, typically between 60–100 psig. These local distribution lines are

It is generally believed that natural gas admixtures containing more than 20 percent hydrogen require pipeline retrofitting so that the hydrogen does not embrittle the pipeline steel.

33 "The Future of Hydrogen: Seizing today's opportunities," *International Energy Agency*, June 2019, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf, (accessed August 23, 2021).

34 Pounds per square in gauge (psig).

generally older and may be made of cast iron, steel, or high-density polyethylene. Natural gas pipelines often have welded joints and compression fittings, which would need to be retrofitted to avoid hydrogen leakage. Distribution lines often have thinner walls than would be acceptable for carrying hydrogen at high pressure.

Dedicated pure hydrogen pipelines can be made of low-strength grade carbon steel, steel without impurities, or micro-alloyed steel. Hydrogen pipeline pressures generally range between 400–2,000 psig.[35] Polyethylene and other plastic pipeline material with reduced permeability may also be an option where low-pressure hydrogen is being transported. Constructing new dedicated pipelines is expected to cost 3–10 times more that the cost of repurposing typical existing natural gas transmission pipelines.

Not counting any costs associated with constructing, retrofitting, or replacing pipelines, transporting hydrogen gas (H2) via pipeline is more economical than transport in containers, especially if blended with natural gas in small volumes, in the short term.[36] The IEA reports that a hydrogen/natural gas admixture is most cost effective to transport through existing infrastructure, though the costs increase linearly with distances beyond 1,500 kilometers (km).[37] Bloomberg New Energy Finance estimates pipeline transport costs between \$0.10/kgH2 to \$0.58/kgH2 for distances between 100 km up to 1,000 km.[38] Hydrogen pipeline transportation costs reach approximately \$1.50/kgH2 up to 1,500 km.

Beyond the 1,500 km (930 miles) distance, IEA estimates show that it becomes more cost effective to convert the hydrogen into ammonia or a liquid organic hydrogen carrier (LOHC) and to transport the ammonia or LOHC via ships, even when accounting for the energy expenditure of converting the ammonia or LOHC back into hydrogen.[39] If the end-use appliance could use the ammonia directly, this would be the most cost-effective option.

To transport hydrogen gas by rail, truck, or ship, the hydrogen must be contained in special compressed gas tube containers at high pressures (as much as 3,000 psig) and low temperatures or the hydrogen must be liquefied into ammonia or a LOHC

35 This pressure range is significantly higher than in existing natural gas pipelines. Depending on the admixture of hydrogen, certain pipeline adaptations will be required. This includes replacing compressors with more powerful ones and installing new and more turbines or motors to deliver the higher volume flow of H2 compared to natural gas.

36 The economics of repurposing pipelines for 100 percent or blended hydrogen or building dedicated pure hydrogen pipelines will likely need case-by-case evaluation. As the amount of hydrogen in the blend increases, so do the costs of retrofitting existing pipelines.

37 Ibid, *International Energy Agency*, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf, (accessed August 23, 2021).

38 Jay Bartlett and Alan Krupnick, "Decarbonized Hydrogen in the US Power and Industrial Sectors: Identifying and Incentivizing Opportunities to Lower Emissions," *Resources for the Future*, December 21, 2020, https://www.rff.org/publications/reports/decarbonizing-hydrogen-us-power-and-industrial-sectors, (accessed August 23, 2021).

39 There are costs and energy losses associated with the conversion and reconversion of hydrogen into ammonia or into an LOHC and back to hydrogen. Ammonia loses between 14%–36% of the energy contained in the hydrogen during the conversion/reconversion process and LOHCs require between 35%–40% of the original hydrogen for the conversion/reconversion process. "The Future of Hydrogen: Seizing today's opportunities," *International Energy Agency*, June 2019, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf, (accessed August 23, 2021).

and transported at low pressure (10 psig) in a cryogenic tank. Transporting hydrogen by container has higher costs than by pipeline. The IEA estimates that transporting hydrogen in pressurized containers by truck costs approximately $2.90/kg for local distribution up to 500 km. The energy consumed transporting hydrogen via tube trailers is much higher than the energy consumed transporting cryogenic tanks for distances over 200 miles.[40]

Despite high capital costs, pipelines have low operational costs and long lifetimes (between 40–80 years). They generally have higher capacities than electric cables, 15–20 GW vs. 1–4 GW, respectively.[41] Again not counting the cost of retrofitting pipelines, transporting up to 20 percent blended hydrogen by existing pipeline is more economical than transporting the energy by electricity over long distances.[42,43] In a situation where either a new pipeline or new electric cables would need to be installed, pipeline construction costs would be the approximately same as electric cables until the distance exceeds 4,000 km.

40 Tan-Ping Chen, "Hydrogen Delivery Infrastructure Option Analysis," United States: N. p., 2010. Web. doi: 10.2172/982359, https://www.osti.gov/servlets/purl/982359-i1bna2, (accessed August 23, 2021). See figure 1-28.

41 Hydrogen transport by pipeline is more cost effective (roughly by a factor of ten) than electricity transport by cable. Also, typically, pipeline capacities (15-20 GW) are much larger than electricity cable capacities (1-4 GW). "A green hydrogen economy: How to make it happen in Europe," *Modern Power Systems*, March 15, 2021, https://www.nsenergybusiness.com/features/renewable-hydrogen-infrastructure, (accessed August 23, 2021).

42 Hydrogen transport via rail or ship is also a cost-competitive option. Energy losses over long-distance transmission lines give pipelines an economic advantage over HVDC cables. HVDC cables lose approximately 3.5% per 1000 km and HVAC cables lose 6.7%. See: Bin Miao, Lorenzo Giordano and Siew Hwa Chan, "Long-distance renewable hydrogen transmission via cables and pipelines," *International Journal of Hydrogen Energy*, May 25, 2021, https://doi.org/10.1016/j.ijhydene.2021.03.067, (accessed August 23, 2021).

43 Volumetric hydrogen in blended fuels has a non-linear relationship with carbon reduction due to hydrogen's low volumetric energy density. For example, a 75% hydrogen blend by volume results in approximately a CO_2 reduction of 50%. However, if the gas flow is set as a percentage of the generating turbine's hear input, the relationship between hydrogen and carbon reduction is linear. See: Jeffrey Goldmeer, "Power To Gas: Hydrogen for Power Generation," *General Electric Company*, February 2019, https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf, (accessed August 23, 2021).

SECTION TWO

THE CONTEXT FOR OFFSHORE WIND TO HYDROGEN IN EUROPE

Many countries in Europe have ambitious carbon reduction goals. The ongoing conversion of electricity supply from fossil-fuel-based power plants to renewable generation has been proceeding well, but heating, transportation, and industry have proven harder to decarbonize. Hydrogen could be a potential solution to decarbonize these sectors. This section addresses how offshore wind in Europe could support hydrogen's development.

OFFSHORE WIND-SPECIFIC DRIVERS

The amount of renewable electricity required to meet the world's potential future green hydrogen demand is considerable. Even if only a modest share of the energy demands from heating, transportation, and industrial sectors are met by green hydrogen, a significant increase in renewable electricity generation will be needed.

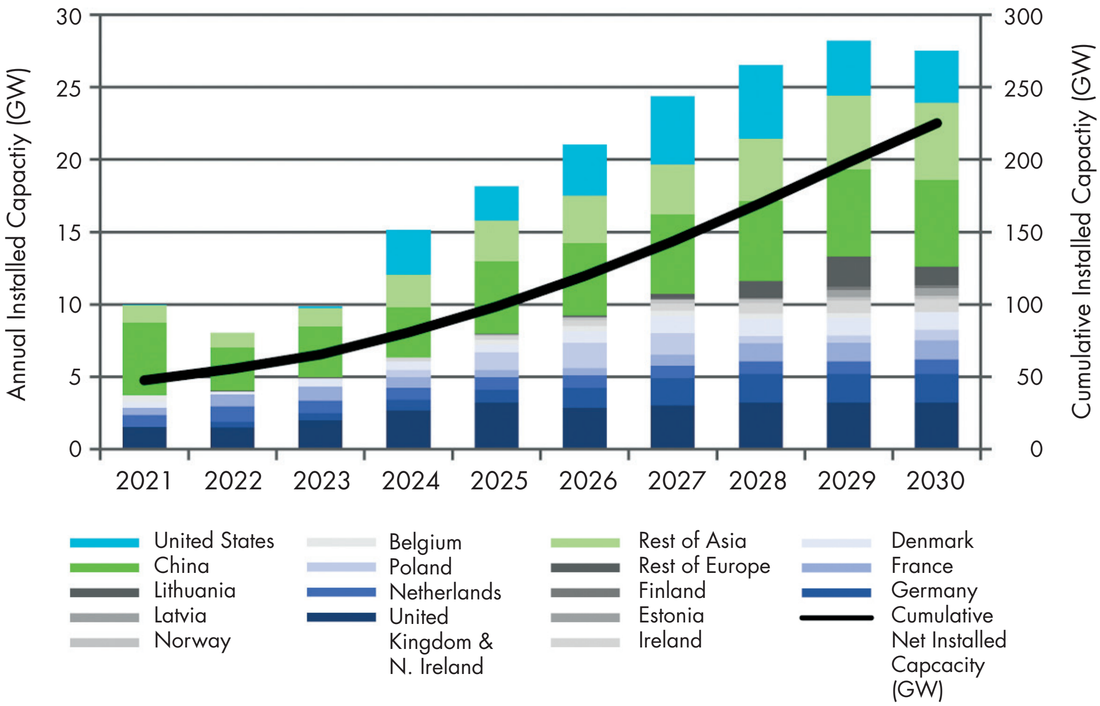
The installed capacity of offshore wind is expected to quadruple globally over the next decade, growing from a cumulative installed capacity of around 50 GW in 2021 to 225 GW in 2030.

The installed capacity of offshore wind is expected to quadruple globally over the next decade, growing from a cumulative installed capacity of around 50 GW in 2021 to 225 GW in 2030. Approximately 50 percent of total offshore wind capacity in the world will be in Europe in 2030; Asia will account for roughly 40 percent of global installed capacity, and the US for the remaining 10 percent (see **Figure 2**, p. 24).

Offshore wind is likely to play an important role in the production of hydrogen in Europe due to the continent's strong offshore wind resources and established offshore wind market. Offshore wind in Europe is particularly suited to the production for hydrogen for the following reasons:

- Europe installed its first offshore wind turbine in 1991. There are now 25 GW of installed offshore wind capacity off Europe's coast, and costs have declined dramatically to €40–€50 per megawatt-hour (MWh). The next phase of offshore wind projects will include 12+ MW turbines and have more capacity than ever before. With limited interconnection points, projected grid constraints, and distance from shore, these projects may be well suited for dedicated hydrogen production or for converting excess capacity to hydrogen.

FIGURE 2: **Global offshore wind capacity forecast to 2030**



Source: BVG Associates

- A key factor effecting the levelized cost of hydrogen (LCOH) is the capacity factor of the electrolyzer; i.e., what percentage of the electrolyzer's maximum production capacity is achieved each year. Offshore wind has a higher capacity factor than other renewables, meaning the electrolyzer can operate for a greater proportion of time and produce more hydrogen.
- Economies of scale will be key to reducing LCOH. Compared with other renewable technologies such as onshore wind and solar PV, individual offshore windfarms have much larger capacity, meaning a single project can achieve economies of scale by installing a large GW-scale electrolyzer plant. Additionally, the ability to interconnect multiple projects could enable multi-GW offshore hydrogen production hubs.
- Many of the end uses of hydrogen, such as with refineries, metal industry, marine transport, and export/import facilities are located on the coast, near to offshore wind farm locations.

There are also drawbacks to using offshore wind to produce hydrogen. Offshore wind has a higher levelized cost of electricity (LCOE) than solar PV and onshore wind. Therefore, it is possible that hydrogen could be produced at a lower cost when produced from large solar PV arrays or large onshore windfarms.

There are other drivers that are creating a particular focus on hydrogen produced from offshore wind in Europe. Offshore wind is seen as a natural transition for many oil and gas companies, which have decades of experience in offshore engineering and are now increasingly focused on transitioning their businesses from fossil fuels to renewable energy. Offshore wind can be used to electrify offshore platforms, decarbonize oil and gas production, and produce hydrogen. For example, in 2020, BP, TotalEnergies, Shell, and Eni acquired 5.4 GW of offshore wind capacity; and in 2021, 4.5 GW out of 7.98 GW of capacity auctioned during the UK Crown Estates Round 4 leasing auction was won by consortiums that included either BP or TotalEnergies.[44]

Hydrogen offers these companies an opportunity to transition their business from producing and trading fossil fuels to producing and trading renewable fuels with similar physical properties.

Hydrogen offers these companies an opportunity to transition their business from producing and trading fossil fuels to producing and trading renewable fuels with similar physical properties. The interests of these large and influential energy majors are a key driver behind the European interest in hydrogen and, in particular, the interest in the combination of offshore wind and hydrogen.

Additionally, there are secondary benefits of hydrogen that address two specific challenges faced by the offshore wind industry: increased offtake risk and insufficient electricity infrastructure.

INCREASED OFFTAKE RISK

As the LCOE of renewables falls, governments will reduce the quantity and value of government-backed price-support schemes. This reduction in price support will result in increased competition between offshore wind projects and other renewables projects such as solar PV and onshore wind farms. This competition will result in offshore wind projects that have little or no government-backed price support. Such projects will need to rely on private power purchase agreements (PPAs) to achieve price certainty and to limit their exposure to price volatility in electricity day-ahead and spot markets.

If an offshore wind project developer can lock in long-term electricity prices through a PPA with green hydrogen producers, that would guarantee price certainty and reduce exposure for both parties and result in predictable hydrogen production costs.

Alternatively, offshore wind farm developers could produce green hydrogen themselves, adding flexibility over when and where they sell electricity, and reducing exposure to price fluctuations in either market.

ELECTRICITY INFRASTRUCTURE

In Wind Europe's 2019 report, *Our energy, our future*, the need to develop sufficient electricity infrastructure was specified as a key challenge to the deployment of future

44 "Offshore Wind Leasing Round 4 signals major vote of confidence in the UK's green economy," *The Crown Estate*, February 8, 2021, https://www.thecrownestate.co.uk/en-gb/media-and-insights/news/2021-offshore-wind-leasing-round-4-signals-major-vote-of-confidence-in-the-uk-s-green-economy, (accessed August 23, 2021).

offshore wind in Europe.[45] The report estimates that new grid developments would need to begin 10 years prior to the installation of new offshore wind capacity. As the installed capacity of offshore wind has increased, so too has the need to upgrade electricity infrastructure and install energy storage. The network upgrades often required to accommodate new offshore windfarms can be costly, and it can be a lengthy process to secure grid connections, limiting the rate at which new offshore wind farms can be installed.

In addition to long lead times, developing new grid infrastructure can be complicated. In Europe, electricity transmission is highly regulated, and investments in new infrastructure require input from multiple stakeholders and careful consideration of how costs will be distributed among users of the grid. Grid upgrades must also contend with planning processes. In most markets, offshore wind farms are connected to the electricity grid via dedicated connection points. This involves offshore cables landing at a point on shore before being connected to the onshore electricity grid. As the number of windfarms increases, and the size of onshore grid infrastructure associated with these windfarms increases, planning restrictions will become more of a concern for developers.[46]

Producing hydrogen from electrolyzer systems connected directly to an offshore windfarm could reduce the size of the required grid connection or eliminate the need for it entirely. Although hydrogen will not replace electricity as the primary energy transmission method for offshore wind, it could supplement it. The ability to reuse existing gas infrastructure could mitigate planning risks associated with new energy transmission infrastructure, and the ability to trade hydrogen between private parties using private infrastructure could alleviate the cost and time required to upgrade the electrical grid. The overall result would be faster energy transmission capacity, enabling a faster rate of deployment for offshore wind.

Another infrastructure challenge that hydrogen could solve lies in its ability to be produced and exported in areas where the offshore wind resource is good, but the transmission capacity for new generation is low. For example, in the north of Scotland, Ireland, and Norway, hydrogen could be exported, enabling the deployment of much more offshore wind capacity than could otherwise be installed and interconnected.

System stability will also be a key challenge in future electricity grids that will become reliant on converter-based generators such as solar PV and wind turbines, with limited physical inertia on the system.[47] Low system inertia can result in poor

45 "Our energy, our future," *Wind Europe,* November 2019, https://windeurope.org/wp-content/uploads/files/about-wind/reports/WindEurope-Our-Energy-Our-Future.pdf, (accessed August 24, 2021).

46 For example, the cumulative impacts of onshore electricity transmission infrastructure have recently been highlighted as an issue in the UK, relating to planning issues for Vattenfall's Norfolk Vanguard projects.

47 System inertia is used to describe how resilient an electricity system is to increases in demand and supply of power, with relation to the system frequency. An electricity system comprised primarily of large synchronous rotating machines, such as steam and gas turbines, has higher inertia meaning the electricity system frequency is more resistant to rapid changes in power demand changes.

power quality and blackouts. Hydrogen generators can be used to provide this physical inertia and stability to the grid.[48]

OFFSHORE WIND TO HYDROGEN CONCEPTS

There are several different offshore wind-to-H2 concepts being considered in Europe. These concepts fall into the following categories:

1. Offshore windfarm with onshore hydrogen production via direct physical connection

In this concept, the offshore windfarm uses offshore substation(s) and high-voltage export cables to transport power back to shore where it is connected to a substation and electrolyzer. This concept can include a connection to the electricity grid, enabling export of power from the offshore windfarm to the grid, and import of additional power to the electrolyzer facility, although the system can also work islanded from the grid.

One benefit of this direct connection is that the system can reduce the size of or remove the need for a grid connection, enabling development of an offshore windfarm where there is good wind resource and hydrogen demand, but insufficient available grid capacity.

2. Offshore windfarm with onshore hydrogen production via PPA

This concept uses a conventional electricity export system connecting an offshore wind farm to the onshore electricity grid. Hydrogen is produced at another location onshore using a grid-connected electrolyzer. The offshore windfarm owner has a PPA in place with the hydrogen production facility owner.

The benefits are that hydrogen production is located at the point of use, reducing costs of hydrogen transportation. Grid connection enables electrolyzers to be used for grid balancing, providing an additional revenue stream.

3. Offshore windfarm with offshore on-turbine hydrogen production

In this concept, each offshore turbine is equipped with an integrated "on-turbine" electrolyzer, and the hydrogen is produced at sea. The turbine platforms would be equipped with desalination technologies to purify the seawater, and the electrolyzers

48 For example, Siemens is upgrading existing gas turbines to run on higher hydrogen blends and developing technology for 100% hydrogen combustion. See: Sonal Patel, "Siemens' Roadmap to 100% Hydrogen Gas Turbines," *Power*, July 1, 2020, https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines, (accessed August 24, 2021).

would split the resulting purified water into hydrogen and oxygen.[49] The hydrogen is then transported to shore via pipeline. Depending on the design of the system, one or more hydrogen compression stations may be required to increase the pressure of the hydrogen for transport. On-turbine hydrogen production systems are being developed for both fixed foundation and floating foundation turbines.

Cost savings can result from this integrated on-turbine-electrolyzer design. In this design concept, the turbines' power train is optimized for hydrogen production, resulting in higher efficiency and lower LCOH. In addition, the cost of exporting hydrogen via pipeline is less per kilometer that that of high-voltage export cables; over long distances, this cost difference may result in hydrogen being the preferred energy transportation medium.

4. Offshore windfarm with offshore central hydrogen production

The central hydrogen production platform concept uses array cables to collect power from wind turbines and delivers the power to a central platform. Electrolyzers at the central platform produce hydrogen that is then transported back to shore via pipeline.

This concept offers cost savings by removing the expense of export cables and onshore substations. This concept is particularly relevant for windfarms further from shore because the cost of hydrogen pipe is lower per kilometer than that of high-voltage export cables.

49 Various research studies are underway analyzing seawater's potential in electrolysis. Harvard University researchers have found that forward osmosis could be effective in splitting water for hydrogen. And a U.S. National Science Foundation-funded team has found that seawater reverse osmosis could be a game changer for the green hydrogen economy at small cost in LCOH. See: "Generating renewable hydrogen fuel from the sea," *National Science Foundation*, October 6, 2020, https://www.nsf.gov/discoveries/disc_summ.jsp?cntn_id=301369&org=NSF&from=news, (accessed August 24, 2021).

SECTION THREE

GREEN HYDROGEN APPLICATIONS FOR DECARBONIZATION

The European Union's Hydrogen Strategy, released in July 2020, outlines a phased approach to green hydrogen development. The strategy's initial phase of green hydrogen sector scale-up (2020–2024) targets the decarbonization of grey hydrogen production, industrial applications, and heavy-duty transport. By Phase Three (2030–2050), hydrogen clusters and a cross-border market develop, and green hydrogen reaches economic maturity and is deployed at large scale. Green hydrogen's growth will be accompanied by significant investments in R&D, innovation, supply chains, electrolyzers, hydrogen production facilities, hydrogen transport, distribution, and storage, and hydrogen demand in end-use sectors. In addition, offshore wind development will need to supply sufficient electricity (or power if electrolyzers are located at the turbines themselves) to meet the demands of projected electrolyzer capacity.

Green hydrogen's growth will be accompanied by significant investments in R&D, innovation, supply chains, electrolyzers, hydrogen production facilities, hydrogen transport, distribution, and storage, and hydrogen demand in end-use sectors.

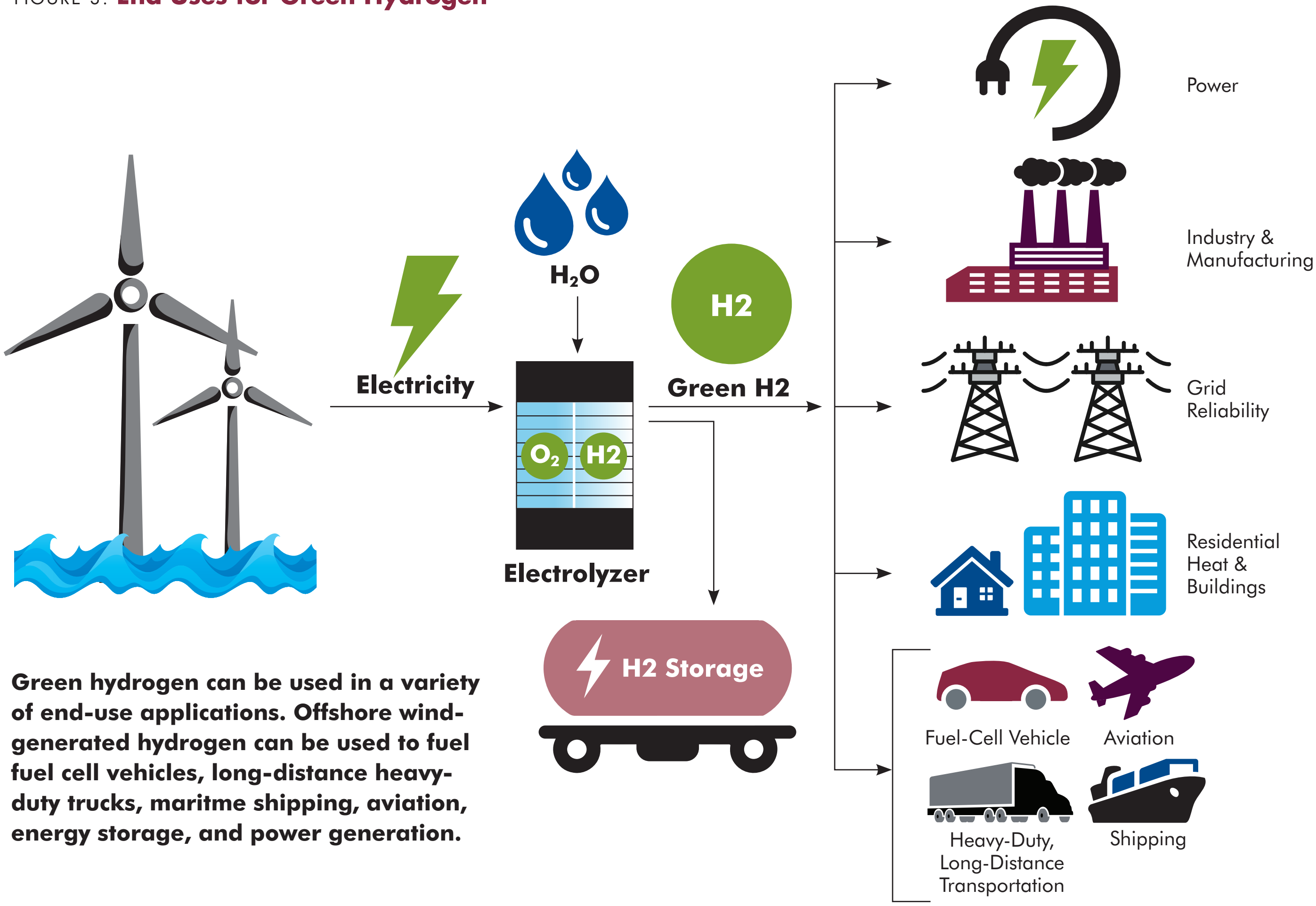
While the EU hydrogen strategy sets the initial financing framework and roll out for green hydrogen development across Europe, several European nations have released hydrogen strategies (many as part of their COVID-19 recovery plans) that guide investments in PtX and present roadmaps for hydrogen development. See **Figure 3**, p. 30 for potential green hydrogen end-uses. Like the EU strategy, most are focused on decarbonizing heavy industry, refineries, and heavy transport. These end-use sectors can use on-site hydrogen production rather than relying on a dedicated hydrogen transportation network, which would take more time and policy to develop. However, hydrogen's roll out in each member state looks a little different. While all include a phased approach that replaces or repurposes the existing natural gas infrastructure, some member states are focused initially on natural gas blending or other end-use sectors. The United Kingdom, for example, is focused on residential heating, whereas Germany's focus includes higher concentrations of hydrogen in the natural gas network.[50]

HYDROGEN FOR HEAVY INDUSTRY

Industry is the most difficult and expensive sector to decarbonize given the high heat and large energy demands called for in many industrial processes. Fossil fuels—

50 The United Kingdeom is no longer a member of the European Union.

FIGURE 3: **End Uses for Green Hydrogen**



Green hydrogen can be used in a variety of end-use applications. Offshore wind-generated hydrogen can be used to fuel fuel cell vehicles, long-distance heavy-duty trucks, maritme shipping, aviation, energy storage, and power generation.

Source: Clean Energy States Alliance

primarily coal and to a lesser extent, natural gas—fuel this sector, generating low- to very-high-temperature heat for industrial processes. The industrial sector consumes more energy than any other sector. In 2017, industry accounted for 149 million terajoules of global energy consumption.[51] As a result, industry is a large source of global CO_2 emissions. Forty-five percent (45%) of industrial energy consumption is used for generating energy that can meet low to very-high-temperature heat demands for industrial processes such as steam reforming, drying, melting, etc. McKinsey estimates that industrial processes up to 1,000°C could be electrified, accounting for nearly 50 percent of industry's energy consumption.[52] Industrial processes that require higher temperatures, such as cement and steel production, could use hydrogen as a substitute for the fossil fuels and coal that currently generate industrial heat and power.

51 Occo Roelofsen et al, "Plugging in: What electrification can do for industry," *McKinsey & Company*, May 28, 2020, https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/plugging-in-what-electrification-can-do-for-industry, (accessed August 25, 2021).

52 Ibid, Roelofsen, *McKinsey & Company*. Electric technologies for industrial processes with a heat demand of up to 400°C are commercially available, including electric furnaces and boilers. However, electric technologies for industrial temperatures above this range up to 1,000°C are not yet commercially available.

Green hydrogen can serve as both a source of heat (fuel) and as a feedstock. In fact, the majority of the world's grey hydrogen is currently used in the industrial sector in refineries, chemical manufacturing, ammonia production, and more. In 2019, the global demand for industrial hydrogen was 71 million metric tons, equivalent to 2,400 terawatt-hours (TWh) of hydrogen.[53] The grey hydrogen is produced at or in close proximity to the industrial facility or cluster. Matching production to meet demand on-site eliminates the difficultly and expense of hydrogen storage and transportation. It also obviates the delay associated with planning, permitting, developing, and regulating hydrogen transportation and storage networks.

Using green hydrogen to meet the existing demands of the industrial sector by directly replacing fossil fuels is considered hydrogen's lowest hanging fruit.

Using green hydrogen to meet the existing demands of the industrial sector by directly replacing fossil fuels is considered hydrogen's lowest hanging fruit. Industrial clusters could use hydrogen produced on-site or could develop around dedicated pipeline infrastructure complemented with large-scale storage. But expert analysis suggests that industrial hydrogen won't be cost competitive until 2040–2050 in Europe, when its production costs are projected to fall below $1.00/kgH2.[54] One optimistic projection suggests that green hydrogen can be cost competitive with coal-produced steel by 2030.[55,56] In addition, to deliver the current amount of hydrogen used for industrial processes from offshore wind would require an installed offshore wind capacity of 830 GW, which is higher than projected future development.[57]

HYDROGEN FOR HEAVY TRANSPORT

Green hydrogen could play an important role in decarbonizing heavy transport; this includes long-distance, heavy-duty trucking, maritime shipping, and aviation. Hydrogen, hydrogen fuel cells, and hydrogen-based fuels can power heavy-duty road freight, ships, buses, trains, and airplanes. While hydrogen fuel cells already power some passenger vehicles, city buses, ferries, and local trains, renewable electrofuels—methane, synthetic liquid fuels (e.g., methanol and kerosene), and ammonia derived from green hydrogen—are projected to be the PtX fuel of choice for the heavy transport sector. Due to the long replacement cycles of ships and airplanes, it will be cheaper to decarbonize shipping and aviation fuels in the short term, while investing in new ships and planes with electric batteries or fuel cells.

53 "Global hydrogen demand by sector in the Sustainable Development Scenario, 2019-2070," *International Energy Agency*, updated September 9, 2020, https://www.iea.org/data-and-statistics/charts/global-hydrogen-demand-by-sector-in-the-sustainable-development-scenario-2019-2070, (accessed August 24, 2021).

54 Ibid, Roelofsen, *McKinsey & Company*, and "Hydrogen Economy Outlook," *BloombergNEF*, March 30, 2020, https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf, (accessed August 24, 2021).

55 Ibid, *BloombergNEF*.

56 Carbon pricing, incentives, or other supportive policies will be needed to help make green hydrogen cost competitive.

57 BVG Associates. The 830 GW projection includes hydrogen for all existing industrial uses; it does not consider any industrial heating applications which could be electrified unless those applications already run on hydrogen.

Road Transport

While the future of passenger vehicles, city buses, and light-duty trucks will rely on electrification, the electrification of long-haul vehicles such as semi-trailer trucks and intercity buses is more difficult; this is where hydrogen fuel cells have an advantage. Fuel cell vehicles with hydrogen fuel cells and hydrogen storage tanks can travel longer distances and with faster recharging times than EVs due to the higher specific energy of hydrogen compared to Li+ batteries. Heavy-duty, long-distance road freight is therefore likely to require hydrogen or biofuels to decarbonize.[58,59] In the European Union, road transport decarbonization is supported by the new Renewable Energy Directive (RED II, 2018)—a legally binding target for 2030 that includes a target of 14 percent renewable energy in road transport. Seven percent (7%) of this binding target is for advanced fuels such as hydrogen and e-fuels whose GHG emissions must be 70 percent lower than those of fossil fuels.[60,61]

Marine Transport

The maritime sector accounts for 5 percent of global oil demand of which 80 percent is used for international freight.[62] PtX electrofuels can serve as drop-in fuels, replacing oil directly; PtX fuels are also easier to store than hydrogen.[63] Ammonia's properties, for example, allow it to "drop in" directly as fuel in traditional marine engines.[64] Freight cargo ships are notorious polluters—their low-grade, crude, heavy-fuel oil accounts for 8 percent of the world's sulfur dioxide emissions and 2.5 percent of global CO_2 emissions.[65] In 2018, the International Maritime Organization (IMO) pledged to reduce the CO_2 emissions from international shipping by at least 50 percent by

58 Kate Forrest et al, "Estimating the technical feasibility of fuel cell and battery electric vehicles for the medium and heavy-duty sectors in California," *Applied Energy*, Volume 276, October 2020, https://www.sciencedirect.com/science/article/abs/pii/S030626192030951X, (accessed August 24, 2021).

59 Heijji Liimatainen, Oscar van Vliet and David Aplyn, "The potential of electric trucks – An international commodity-level analysis," *Applied Energy*, Volume 236, February 15, 2019, https://www.sciencedirect.com/science/article/pii/S0306261918318361, (accessed August 25, 2021).

60 "Renewable Energy – Recast to 2030 (RED II)," *European Commission*, Updated July 23, 2019, https://ec.europa.eu/jrc/en/jec/renewable-energy-recast-2030-red-ii, (accessed August 25, 2021).

61 "REDII national implementation," *Transport & Environment*, January 2020, https://www.transportenvironment.org/sites/te/files/publications/2020_01_REDII_general_implementation_briefing.docx_.pdf, (accessed August 25, 2021).

62 "The Future of Hydrogen: Seizing today's opportunities," *International Energy Agency*, June 2019, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf, (accessed August 25, 2021).

63 Ammonia, for example, is more energy dense than hydrogen and takes up less space. It is also a liquid and can be stored at low pressure.

64 "PTX In Denmark Before 2030," *ENERGINET*, April 2019, https://energinet.dk/-/media/8BF0CD597E1A457C8E9711B50EC2782A.PDF, (accessed August 25, 2021).

65 "The Future of Hydrogen: Seizing today's opportunities," *International Energy Agency*, June 2019, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf, (accessed August 25, 2021).

2050, compared to 2008 levels.[66] The world's largest container shipping company, Maersk, is leading the way for the sector's decarbonization, committing to carbon neutrality by 2050. Ammonia can serve as a replacement fuel, eliminating the sector's sulphur oxides (SOx) and particulate matter ($PM_{2.5}$) emissions. IEA analysis shows that for long-distance freight cargo ships, a carbon price (or policy equivalent) of \$40–\$230/tCO_2 would make green ammonia cost competitive with oil.[67]

Offshore wind service and installation vessels are also decarbonizing with hydrogen and e-fuels. Ulstein has designed two hybrid-hydrogen vessels to service the offshore wind installation market, the Ulstein SX190 Zero Emission DP2 construction support vessel and the Ulstein J102 jack-up installation vessel.[68] And the GustoMSC NG-14000XL-G, a heavy lift wind turbine installation vessel, will have a traditional propulsion system designed so that it can be retrofitted with hydrogen fuel cells.[69]

Aviation

Aviation is perhaps the most difficult transport sector to decarbonize due to the need to keep weight to thrust ratio low—the specific energy of fuels plays an important role: and the more energy per kilogram (kg) of fuel, the better. Currently, hydrogen has a much higher specific energy than battery storage and may ultimately be the most viable path for aviation decarbonization.

Aviation is perhaps the most difficult transport sector to decarbonize due to the need to keep weight to thrust ratio low—the specific energy of fuels plays an important role.

In 2019, the International Air Transport Association established targets for reducing CO_2 emissions from aviation by 50 percent in 2050 compared to 2005 levels.[70] The EU's carbon market, supported by the Emissions Trading Scheme (ETS) policy, limits emissions from heavy energy end-use sectors, including aviation. The steeply climbing price of carbon per ton (currently €50/tCO_2) and the limited availability of CO_2 certificates are driving investment in and funding for innovative technologies for net-zero transportation.[71] However, IEA

66 In January 2020, the IMO began requiring that shipping fuel contain no more than 0.5 percent sulfur (compared to a previous limit of 3.5 percent). See: Maria Gallucci, "At Last, the Shipping Industry Begins Cleaning Up Its Dirty Fuels," *Yale Environment 360*, June 28, 2018, https://e360.yale.edu/features/at-last-the-shipping-industry-begins-cleaning-up-its-dirty-fuels, (accessed August 25, 2021).

67 Mandates and low carbon fuel standards can help hydrogen-based electrofuels compete with their fossil-fuel counterparts. The IEA analysis assumes a 15-year first-owner calculation. See: "The Future of Hydrogen: Seizing today's opportunities," *International Energy Agency*, June 2019, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf, (accessed August 25, 2021).

68 "Zero-emission turbine installation is today's reality," *Ulstein*, Newsletter, October 2, 2020, https://ulstein.com/news/2020/zero-emission-turbine-installation-is-todays-reality, (accessed August 25, 2021).

69 "NOV wins contract for OHT wind turbine installation vessel new build," *NOV*, February 10, 2021, https://www.nov.com/about/news/nov-wins-contract-for-oht-wind-turbine-installation-vessel-new-build, (accessed August 25, 2021).

70 "Carbon Offsetting for International Aviation," *International Air Transport Association*, June 2020, https://www.iata.org/contentassets/fb745460050c48089597a3ef1b9fe7a8/paper-offsetting-for-aviation.pdf, (accessed August 25, 2021).

71 "Tracking the European Union Emissions Trading System carbon market price day-by-day," *Sandbag, Carbon Price Viewer*, https://sandbag.org.uk/carbon-price-viewer, (accessed August 3, 2020).

estimates that a carbon price from $115/$tCO_2$ to $660/$tCO_2$ would be needed to shift to green electrofuels in the aviation sector.[72] Like the long replacement cycles in shipping, the aviation sector is likely to rely on replacement PtX fuels such as synthetic kerosene for its decarbonization pathway, at least to 2050. Synthetic kerosene, and to a lesser extent, biokerosene, will be the least cost pathway to the aviation sector's fuel mix. Hydrogen fuel cell-powered jet engines may be a longer-term solution.

Stakeholders such as the Fuel Cell and Hydrogen Joint Undertaking are partnering on research and development on hydrogen fuel cell (HFC)-propelled jets.[73] Commuter and short- to medium-range airplanes may be suited to HFC propulsion or a hybrid combustion and HFC approach.[74] The world's first passenger hydrogen aircraft recently carried out test flights on the Orkney Islands in the UK. ZeroAvia, supported by funding from the UK government through the HyFlyer program, is developing a six-seat passenger aircraft using a hydrogen fuel cell propeller propulsion system.[75] Airbus is also pursuing its own hydrogen development program, ZEROe. It is developing three aircraft types all fueled by hydrogen, with an ambition to develop its first zero-emission commercial aircraft by 2035.[76]

In 2019, 3,780 TWh of aviation fuel was used globally. To deliver this energy from offshore wind derived hydrogen would require an offshore wind installed capacity of 785 GW.

HYDROGEN FOR GRID RESILIENCY

Green hydrogen can also play a role in integrating growing amounts of variable renewable energy resources (VERs) on the grid. When there is a surplus of offshore wind, hydrogen can be produced cost effectively and stored. In turn, in times of grid demand, stored hydrogen can be used in fuel cells or turbines to produce electricity to meet peak demands.[77] Hydrogen's niche is in its ability to provide long-duration large-scale storage, an area where few alternative technologies exist, see **Figure 4**, (p. 35). According to the IEA, hydrogen is the most cost-effective storage option for

72 "The Future of Hydrogen: Seizing today's opportunities," *International Energy Agency*, June 2019, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf, (accessed August 25, 2021).

73 Innovation is needed to improve the overall efficiency of fuel cell systems, to develop lighter tanks for storing H2, and to improve turbines that can burn H2 with low NOx emissions. Long-range aircrafts will likely require design changes to accommodate on-board hydrogen tanks.

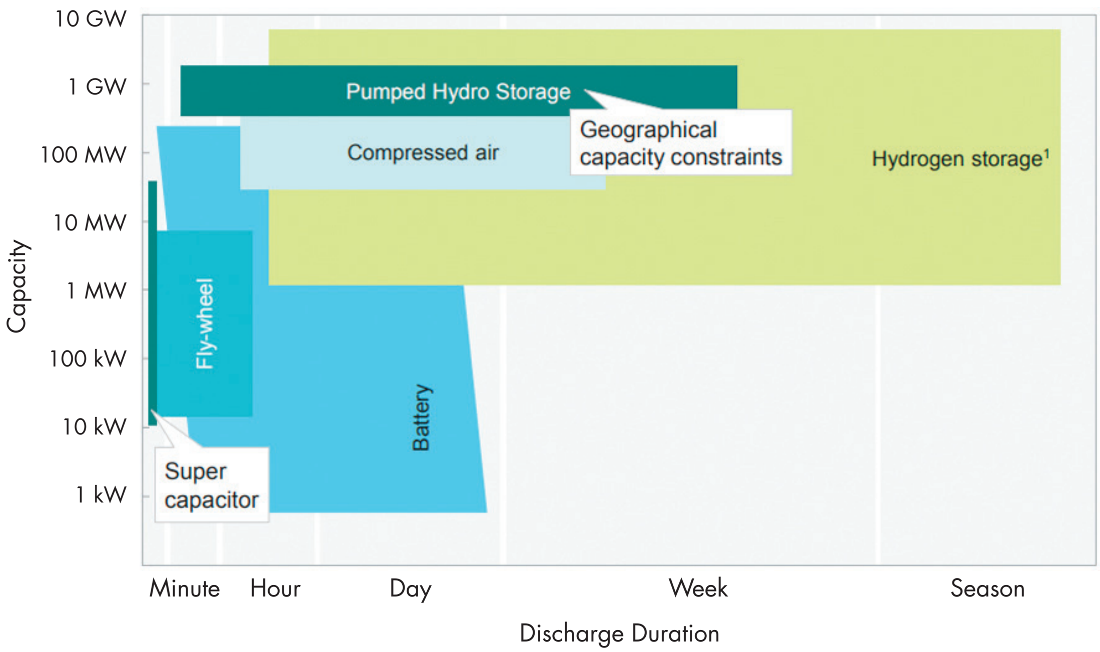
74 "Hydrogen-powered aviation: A fact-based study of hydrogen technology, economics, and climate impact by 2050," *McKinsey & Company* for the Clean Sky 2 JU and FCH 2 JU, May 2020, https://www.euractiv.com/wp-content/uploads/sites/2/2020/06/20200507_Hydrogen-Powered-Aviation-report_FINAL-web-ID-8706035.pdf, (accessed August 25, 2021).

75 "ZeroAvia Completes World First Hydrogen-Electric Passenger Plane Flight," *ZeroAvia*, September 25, 2020, https://www.zeroavia.com/press-release-25-09-2020, (accessed August 25, 2021).

76 "ZEROe: Towards the world's first zero-emission commercial aircraft," *AIRBUS*, https://www.airbus.com/innovation/zero-emission/hydrogen/zeroe.html, (accessed August 3, 2020).

77 Fuel cells have an efficiency range of 50-60 percent, similar to combined-cycle gas turbines. While green hydrogen can be combusted in turbines, due to NOx emission concerns, combustion for power generation is not advised.

FIGURE 4: **Optimal power and discharge duration characteristics of energy storage technologies**



Hydrogen excels at seasonal storage because of the magnitude of its discharge duration and power compared to other storage technologies.

Source: Hydrogen Council, "How hydrogen empowers the energy transition" (January 2017), p.7, https://hydrogencouncil.com/wp-content/uploads/2017/06/Hydrogen-Council-Vision-Document.pdf

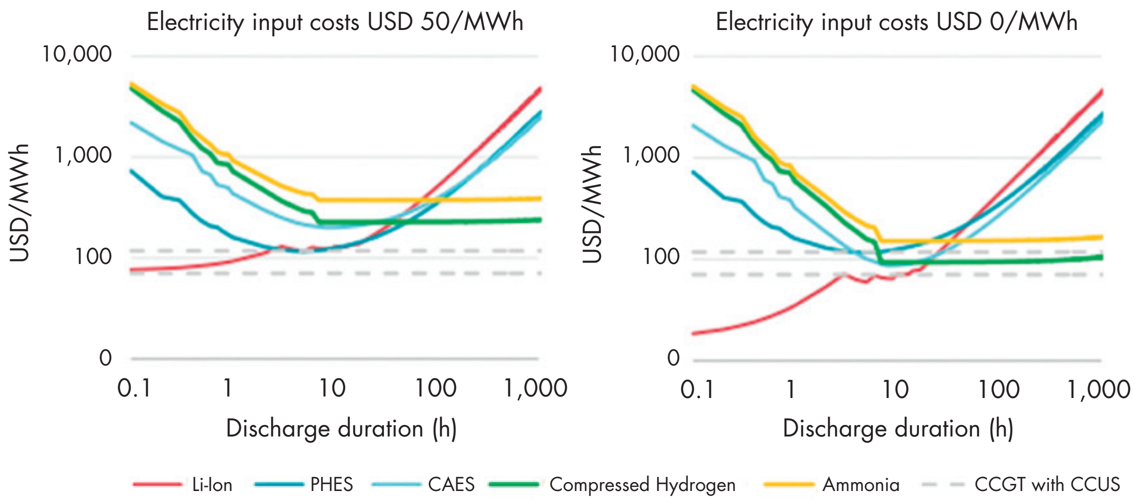
durations beyond 20–45 hours.[78,79] (See **Figure 5**, p. 36.) With on-site hydrogen availability, hydrogen energy storage can address longer demand periods than battery energy storage. The longer the storage duration desired, the more on-site hydrogen storage tanks are needed. Alternatively, a direct hydrogen link between offshore wind farms and on-site electrolyzers can fuel the fuel cells. Large volumes of hydrogen, such as can be accommodated by salt cavern storage, can serve as seasonal storage.

> ***With on-site hydrogen availability, hydrogen energy storage can address longer demand periods than battery energy storage. The longer the storage duration desired, the more on-site hydrogen storage tanks are needed.***

78 "The Future of Hydrogen: Seizing today's opportunities," *International Energy Agency*, June 2019, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf, (accessed August 25, 2021).

79 Flow batteries are also proving to be a promising long-duration storage technology. And Form Energy recently announced the successful development of a 100-hour iron air flow battery. See: "Enabling a 100% Renewable Grid," *Form Energy*, https://formenergy.com/technology/battery-technology, (accessed September 7, 2021).

FIGURE 5: **Levelized costs of storage as a function of discharge duration**



At longer discharge durations, hydrogen for energy storage becomes a more economic option, depending on the price of electricity.

Notes: PHES = pumped-hydro energy storage; CAES = compressed air eerngy storage; LiIon = lithium-ion battery. Compressed hydrogen storage refers to compressed gaseous storage in salt caverns, ammonia storage to storage in tanks.

Source: IEA, "The Future of Hydrogen: Seizing today's opportunities" (2019) page 159.

HYDROGEN FOR HEATING

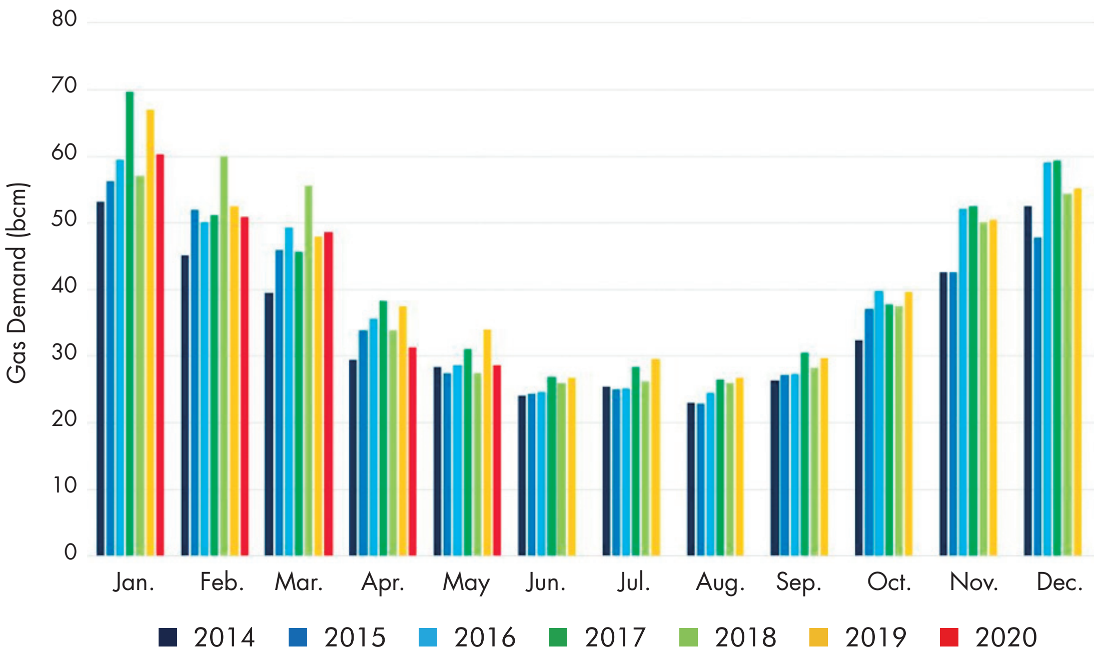
Buildings are responsible for nearly 40 percent of global energy use and 39 percent of global emissions. In 2019, buildings contributed 10 gigatons of CO_2 emissions, reaching a record high.[80] In Europe, heating and cooling buildings accounts for 50 percent of total primary energy demand. Fossil fuels are the predominant source of building heat; natural gas, in particular, provides 41 percent of building heat, though amounts vary from country to country. Various studies have compared different pathways for the decarbonization of the heating and cooling sector in Europe but have not led to consensus on the most cost-effective solution; the decarbonization approach will likely vary from country to country depending on the current predominant heating fuel.[81] For example, the UK heats approximately 80 percent of its buildings with natural gas, whereas in Norway, natural gas accounts for less than one percent of building heat. See **Figure 6** (p. 37) for monthly natural gas demand in Europe.

Hydrogen could potentially be used for residential and commercial space and water heating and district heating. Green hydrogen could be transported to homes, businesses, and district heating plants via natural gas pipeline. Currently, a hydrogen

80 "2019 Global Status Report for Buildings and Construction," *International Energy Agency* for the Global Alliance for Buildings and Construction, 2019, https://wedocs.unep.org/bitstream/handle/20.500.11822/30950/2019GSR.pdf, (accessed August 26, 2021).

81 Anouk Honoré, "Decarbonisation of heat in Europe: Implications for natural gas demand," *Oxford Institute for Energy Studies*, 2018, https://ora.ox.ac.uk/objects/uuid:c808f872-16de-4d88-8190-5c17abcae0bd/download_file?file_format=pdf&safe_filename=Decarbonisation-of-heat-in-Europe-implications-for-natural-gas-demand-NG130.pdf&type_of_work=Working+paper, (accessed August 26, 2021).

FIGURE 6: **Monthly natural gas demand in Europe for the period 2014–2020**



The chart shows the monthly gas demand in Europe for the past six years and highlights the magnitude of seasonal variability. Gas demand in the peak heating month, January, can be more than double that of the summer months.

Source: University of Oxford

admixture between 3–20 percent is considered technically and safely feasible, but some demonstration and pilot projects are blending green hydrogen into natural gas pipelines in higher concentrations.[82] Proponents of hydrogen for heat argue that this is a less disruptive decarbonization pathway for heating because the hydrogen can repurpose existing natural gas infrastructure and building owners can use their existing heating systems with minor changes. Beyond this admixture range, however, end-use appliances would need to be replaced to handle higher hydrogen concentrations.

Hydrogen-based heating is less efficient than heating electrification with heat pumps. Some studies suggest that it would be more cost effective to decarbonize buildings' heat demand through electrification rather than with hydrogen. Building electrification is particularly relevant for countries with air conditioning needs because heat pumps can be used in reverse mode for cooling.

Several initiatives across Europe are investigating the feasibility of pure hydrogen transport or hydrogen blends through existing natural gas infrastructure for delivery

82 "Hydrogen: A Renewable Energy Perspective," *International Renewable Energy Agency,* Report prepared for the 2nd Hydrogen Energy Ministerial Meeting in Tokyo, Japan, September 2019, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf, (accessed August 30, 2021).

83 "A hydrogen strategy for a climate-neutral Europe," *Communication From The Commission to The European Parliament, The Council, The European Economic and Social Committee and The Committee of The Regions,* August 7, 2020, https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf, (accessed August 30, 2021).

to domestic buildings. Europe's Hydrogen Strategy envisions that between 2025 and 2030, hydrogen clusters or "hydrogen valleys" will develop, initially servicing industrial and transport sectors, and then providing heat for residential and commercial buildings.[83] Twenty-three European gas infrastructure companies have put forth a European Hydrogen Backbone plan for large-scale hydrogen transport infrastructure across Europe to support this vision.

The United Kingdom is the country with the greatest interest in hydrogen for heating buildings. There, 85 percent of homes currently rely on natural gas heating and hot water. The interest in hydrogen for heating is in part fueled by fear of growing grid strains from increased peak demand if all home heating were electrified. Thus, the UK government is interested in decarbonizing residential heating with green hydrogen more so than through electrification. Through its ten-point climate and green recovery plan, the UK aims to invest in hydrogen for home heating and cooking.

Despite the UK interest in hydrogen for residential heating, it will be difficult for hydrogen to compete against heating electrification globally.

Despite the UK interest in hydrogen for residential heating, it will be difficult for hydrogen to compete against heating electrification globally. IEA analysis shows that final energy prices for hydrogen would need to be in the $1.50–$3.00/kgH2 to be cost competitive with electric heat pumps and higher (up to $3.50/kgH2) with natural gas. In the US, hydrogen costs would need to be around $1.50/kgH2 to be cost competitive with both electrification and natural gas. Additional research on the appliance retrofits needed to combust higher concentrations of hydrogen is needed, as well as on the NOx emissions' impacts from the combustion of hydrogen for residential heating.

Hydrogen may be relatively more cost effective for larger buildings and district heating. Electrolysis and hydrogen fuel cells produce heat as a byproduct; this heat can be used in district heating systems, increasing the efficiency of fuel cells to 80 percent. Large buildings, campuses, and other building complexes could use co-generation fuel cell units to meet both electricity and thermal demands with 100 percent hydrogen.

HYDROGEN FOR POWER GENERATION

Hydrogen combustion does not produce carbon emissions and can thus lead to a reduction in CO_2 emissions compared to the combustion of natural gas, other hydrocarbons, or coal. However, hydrogen blend combustion could result in higher levels of nitrogen oxides (NOx) when used with existing gas turbines.

84 "Stationary Gas and Combustion Turbines: New Source Performance Standards (NSPS)," *United States Environmental Protection Agency*, https://www.epa.gov/stationary-sources-air-pollution/stationary-gas-and-combustion-turbines-new-source-performance, (accessed August 20, 2021).

Older, diffusion burners yield higher NOx emissions and are not suitable for hydrogen blend combustion. This means that hydrogen cannot be safely added to the fuel supply of most existing natural gas generators without modifications to the system. With current mitigation and operational strategies, increases in NOx emissions from hydrogen blends can be limited to single-digit increases in parts per million (ppm) compared to emissions from natural gas. (For US context, current EPA regulations for NOx for combined cycle gas turbines is 25 ppm, though limits vary by state and can be lower.)[84]

More modern low-NOx (lean or pre-mixed) burners yield lower NOx emissions (between 1–40 ppm).[85] NOx emissions from hydrogen blends are related to flow speed, volume, and flame temperature, which can be controlled by modern low NOx turbines (dry low NOx or DLN). Major gas turbine manufacturers in Europe are developing low-NOx turbines for pure hydrogen and hydrogen blends; advanced DLN combustion turbines may enable higher admixtures with minimal impact on NOx emissions.[86]

Recent European hydrogen strategies recognize the possibility of using hydrogen and hydrogen-based fuel admixtures to decarbonize the power sector but do not have specific targets for that sector. Currently, hydrogen does not play a large role in the power sector. Hydrogen and hydrogen-based fuel admixtures are mostly limited to 3–5 percent blends in natural gas pipelines in power systems with conventional gas turbines, and the direct combustion of 100 percent hydrogen is limited to a few small projects. There are a few exceptions where higher hydrogen admixtures are permitted, and admixtures of 20–97 percent are being trialed.[87]

These blends can reduce the carbon emissions associated with the combustion of natural gas, but not significantly at low hydrogen blends. The amount of hydrogen in the blend has a non-linear relationship to the CO_2 emission reduction. A 5 percent admixture reduces carbon emissions by only 1.6 percent, whereas a 75 percent blend can reduce carbon emissions by 50 percent.[88]

85 NOx emissions are highly variable and depend on turbine technology, operational and mitigation strategies, and combustion techniques. See: U.S. Environmental Protection Agency, "Technical Bulletin: Nitrogen Oxides (NOx), Why and How They Are Controlled," *Clean Air Technology Center*, November 1999, https://www3.epa.gov/ttncatc1/cica/files/fnoxdoc.pdf, (accessed August 30, 2021).

86 Turbine manufacturers are working to improve DLN fuel flexibility up to 50% hydrogen. More research is needed to develop turbines that can handle fuel flexibility from 1%-100% hydrogen. Turbines that burn one hundred percent hydrogen already exist but tend to be diffusion-based burners with modifications. The Fusina project described on page 40 uses an older combined cycle gas (diffusion) burner.

87 Most experts believe that blends of 20%-30% hydrogen by volume are within the tolerance limits of modern gas turbines.

88 Hydrogen has a much lower energy density than natural gas (only one-third the heating value) on a volumetric basis. Thus, as the amount of H2 in the blend increases, the average energy intensity of the blended gas falls. See: Zane McDonald, "Injecting hydrogen in the natural gas grid therefore has a low CO_2 emissions reduction potential compared grids could provide steady demand the sector needs to develop other end-use applications," *S&P Global Platts*, May 19, 2020, https://www.spglobal.com/platts/en/market-insights/blogs/natural-gas/051920-injecting-hydrogen-in-natural-gas-grids-could-provide-steady-demand-the-sector-needs-to-develop, (accessed August 30, 2021). See the non-linear relationship between blended hydrogen and CO_2 here: Jeffrey Goldmeer, "Power To Gas: Hydrogen for Power Generation," *General Electric Company*, February 2019, https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf, (accessed August 30, 2021).

Gas turbine manufacturers in Europe are developing engines to run on higher hydrogen concentrations and entirely on hydrogen with limited NOx emissions.[89] Manufacturers continue to develop and test gas turbines that are able to handle higher concentrations of hydrogen with low NOx emissions; these prototypes are expected to be in commercial production in the late 2020s or early 2030s.[90] The Dutch government is currently funding a demonstration project with industry partners to develop a combustion turbine retrofit to deliver NOx emissions below 9 ppm (18 mg/Nm^3) in 0–100 percent hydrogen admixtures.[91]

Turbine manufacturer Siemens offers combined cycle gas turbines for both small and large applications that can burn up to 30 percent hydrogen, and it is developing large gas turbines to run on 100 percent hydrogen by 2030. Its utility-scale dry low emissions burner design can run on 27 percent hydrogen with NOx emissions at or below 24 ppm (50 mg/Nm^3), which is below the EU's Industrial Emissions Directive limit of 150 mg/Nm^3.[92,93]

Enel, Italy's largest utility, was the first to operate and demonstrate an industrial-scale, hydrogen-fired combined cycle gas turbine (CCGT). Enel burns a 97.5 percent hydrogen fuel mix at its Fusina 16-MW power plant, avoiding 17,000 tons of CO_2 emissions annually.[94] The Fusina facility has NOx emissions below 49 ppm (100 mg/Nm^3).[95]

In the Netherlands, Vattenfall, Nuon, Gasunie, and Statoil are collaborating to transform one of three 440 MW combined cycle natural gas turbines at the Magnum power plant to 100 percent hydrogen by 2023. This site was chosen due to its Mitsubishi

89 Not all combustion systems emit the same levels of NOx. NOx emissions depend on the combustion design—diffusion flame vs. lean, premixed combustor. Hydrogen has a lower heating value, is less energy dense on volume basis, and more energy dense on a mass basis than natural gas or methane, so three times more hydrogen flow is needed to provide the same amount of heat. A gas turbine combusting hydrogen needs to account for this flow difference as well as increase the flame speed to ensure full combustion. Dry low NOx gas turbine systems can currently handle hydrogen admixtures up to about 30 percent, but not higher levels of hydrogen. Special combustion systems such as aeroderivative, heavy-duty, and dry low emission (lean premix combustion) gas turbines can handle higher up to 100 percent hydrogen (by volume) and the premixed systems can be designed for near-zero NOx emissions with the same NOx emissions of a newer natural gas plant or lower. See: Ben Emerson and Tim Lieuwen, "Hydrogen substitution for natural gas in turbines: Opportunities, issues, and challenges," *Power Engineering*, June 18, 2021, https://www.power-eng.com/gas/hydrogen-substitution-for-natural-gas-in-turbines-opportunities-issues-and-challenges/#gref, (accessed August 30, 2021).

90 Several turbine manufacturers have pledged to reach 100% hydrogen combustion by 2030. Wet low emission units and dry low emission turbines use different technology to abate carbon and NOx emissions.

91 "Hydrogen Gas Turbines: The Path Towards a Zero-Carbon Gas Turbine," *European Turbine Network*, January 2020, https://etn.global/wp-content/uploads/2020/02/ETN-Hydrogen-Gas-Turbines-report.pdf, (accessed August 30, 2021).

92 The turbine emits the same amount of NOx whether it combusts natural gas or hydrogen. "Working toward 100% hydrogen," *Gas Turbine World*, March 20, 2020, https://gasturbineworld.com/working-toward-100-percent-hydrogen, (accessed September 7, 2021).

93 Andy Brown and Mike Welch, "Hydrogen as a Fuel for Gas Turbines," *The Chemical Engineer*, March 2, 2020, https://www.thechemicalengineer.com/features/hydrogen-as-a-fuel-for-gas-turbines, (accessed August 30, 2021).

94 The Fusina hydrogen plant uses a 12-MW hydrogen-fueled gas turbine and a condensing-type heat recovery steam generator for energy recovery. See: "Fusina: Achieving low NOx from hydrogen combined-cycle power," *Power Engineering International*, October 1, 2010, https://www.powerengineeringint.com/world-regions/europe/fusina-achieving-low-nox-from-hydrogen-combined-cycle-power, (accessed August 30, 2021).

95 Nm3 means normal cubic meter of air. This is a common industry unit for referring to emissions.

dry low-NOx combined cycle gas turbines, which is designed to run on various types of fuel (including high hydrogen content fuels) with limited NOx emissions. The modified M701F turbine will remain at the same NOx emissions level at 100 percent hydrogen as it had with natural gas.[96]

With current electrolyzers, green hydrogen's efficiency, from production back to energy through combustion, falls between 18–45 percent, which means that 55–82 percent of the renewable energy put into producing green hydrogen is lost across the full cycle of production and use.

Stationary fuel cells can also provide electricity (and heat) in a range of applications—microgrids, micro co-generation units, off-grid power supply (e.g., telecommunications), and at various scales—from hundreds of kilowatts to megawatt scale.[97] Most of the stationary fuel cell capacity is in Japan, Korea, the US, and Germany.[98]

It is especially worth noting hydrogen's round-trip efficiency losses. With current electrolyzers, green hydrogen's efficiency, from production back to energy through combustion, falls between 18–45 percent, which means that 55–82 percent of the renewable energy put into producing green hydrogen is lost across the full cycle of production and use.[99] The efficiency could be higher if the green hydrogen were used for heating instead of electricity because the thermal energy could be captured and available for heating.[100] Next generation electrolyzers could have an efficiency cycle of 80 percent, bringing green hydrogen's total efficiency to between 45–50 percent.

96 Darrell Proctor, "High-Volume Hydrogen Gas Turbines Take Shape," *Power*, May 1, 2019, https://www.powermag.com/high-volume-hydrogen-gas-turbines-take-shape, (accessed August 30, 2021).

97 Stationary fuel cells currently have a maximum power output of 50 MW, compared to the output of combustion gas turbines at 400 MW. See: "The Future of Hydrogen: Seizing today's opportunities," *International Energy Agency*, June 2019, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf, (accessed August 30, 2021)

98 Ibid, *International Energy Agency*.

99 Tom DiChristopher, "Hydrogen technology faces efficiency disadvantage in power storage race," *S&P Global*, June 24, 2021, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/hydrogen-technology-faces-efficiency-disadvantage-in-power-storage-race-65162028, (accessed August 30, 2021).

100 Jason Deign, "The Reality Behind Green Hydrogen's Soaring Hype," *Greentech Media*, November 28, 2019, https://www.greentechmedia.com/articles/read/the-reality-behind-green-hydrogens-soaring-hype, (accessed August 30, 2021).

SECTION FOUR

HYDROGEN BLENDING

To blend or not to blend or how much to blend are questions European countries are seeking to address. Although hydrogen and hydrogen-blends are not cost competitive with natural gas, blending is seen as a quick path to scaling up hydrogen. Proponents argue that blending is an affordable transitional solution while a dedicated hydrogen network is being built. However, the higher levels of NOx emissions and its impact on public health must be considered and addressed prior to increasing the hydrogen admixture in natural gas. Moreover, opponents argue that it is more economical and efficient—and would result in greater carbon emissions reductions—to use hydrogen directly in hard-to-decarbonize sectors first and to procure as much electricity as possible from renewables such as wind or solar.

The higher levels of NOx emissions and its impact on public health must be considered and addressed prior to increasing the hydrogen admixture in natural gas.

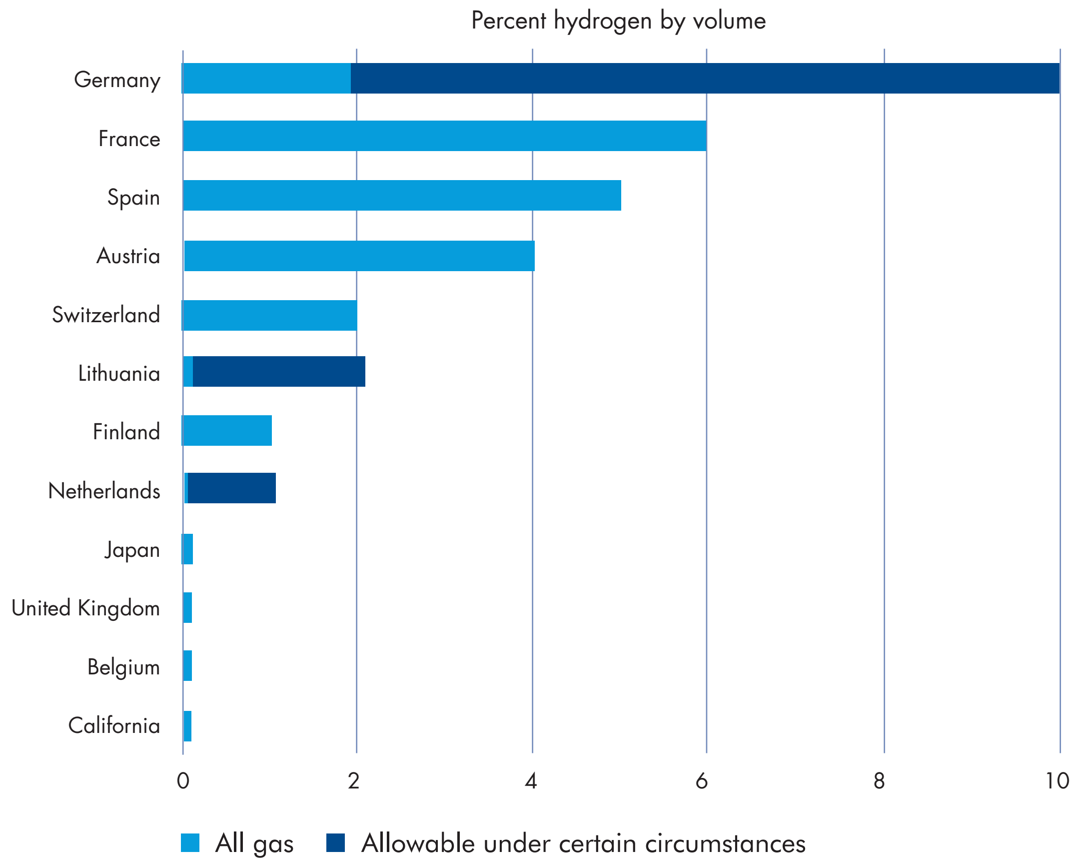
Many European countries permit blending hydrogen with natural gas between 0.1 percent to 12 percent by volume (though there are a few countries that prohibit blending altogether), as well as demonstration projects that are testing higher admixtures (see HyDeploy project described in a case study in the Appendix).[101] Hydrogen admixtures are limited generally by the compatibility of downstream appliances. The national limits are set by legislation or by long-standing gas safety standards. There are currently no gas transmission system operators that allow for 100 percent hydrogen in natural gas pipelines, but Germany and the Netherlands are interested in and investigating an accelerated transition to 100% hydrogen pipelines.

There is no clear consensus across Europe whether, and to what extent, hydrogen should be blended into natural gas grids (see **Figure 7**, p 43). Blending advocates argue that hydrogen admixtures can be an intermediary step on the path to a pure hydrogen grid. Other advocates, such as Clean Energy Group, have found that hydrogen admixtures for combustion in power generation should raise red flags: "…blended hydrogen combustion does not appear to have the technology in hand to control those [NOx] emissions at any but negligible levels."[102]

101 Examples of countries that permit blending up to 0.5 percent: the UK, Belgium, and Sweden. Germany permits blending up to 10 percent and Holland permits blending up to 12 percent. See: Joseph Allen Ronevich and Christopher W. San Marchi, "Hydrogen Blending into Natural Gas," *U.S. DOE Office of Energy Efficiency and Renewable Energy*, July 1, 2019, https://www.osti.gov/servlets/purl/1645686, (accessed August 30, 2021). Some countries do not have a maximum level set for hydrogen: Denmark, Spain, and Romania are examples. See: Alexandru Floristean et al, "HyLaw: Deliverable 4.1–Cross Country Comparison," November 3, 2018, https://www.hylaw.eu/sites/default/files/2018-11/D.4.1%20-%20Analysis%20of%20commonalities%20and%20differences%20between%20countries.pdf, (accessed August 30, 2021).

102 Lewis Milford, Seth Mullendore and Abbe Ramanan, "Hydrogen Hype in the Air," *Clean Energy Group*, December 14, 2020, https://www.cleanegroup.org/hydrogen-hype-in-the-air, (accessed August 30, 2021).

FIGURE 7: **Limits on hydrogen blending in natural gas networks, 2018**



The legal limits of the amount of hydrogen injected into natural gas networks vary by country.

Source: IEA, Limits on hydrogen blending in natural gas networks, 2018, IEA Paris, https://www.iea.org/data-and-statistics/charts/limits-on-hydrogen-blending-in-natural-gas-networks-2018.

Blending can support market scale-up for industrial and transportation hydrogen markets, as blending is an "easy" way to reach the volume required for cost reductions. However, retrofitting of equipment is necessary because hydrogen is a small molecule that can leak through many materials, including rubber and some steel, and can escape through improperly sealed pipeline joints. The extent of retrofit measures to accommodate hydrogen will depend on the hydrogen admixture, but retrofits of existing gas grids would require changes to ensure that the controls and pressure valves are suitable for safe hydrogen transport and that analytical and monitoring instruments account for hydrogen's unique properties.

END-USE APPLICATIONS FOR HYDROGEN BLENDS

European countries are interested in hydrogen blending mainly to decarbonize industry, heavy transport, and heating; and investments are being made in the production, distribution, and retrofitting of end-use appliances in advance of a larger hydrogen roll out. An opportunity exists to take advantage of the established national natural gas grids for hydrogen storage and distribution to efficiently reach these sectors.

However, Europe does not currently have a legal framework in place for power-to-gas (PtG) systems, PtG access to the natural gas grid, and market access; and its member states are still developing regulatory frameworks for the transmission, distribution, ownership models, and operation of PtG. The current demonstration projects are operating under special permissions.[103] Higher blending trials are being demonstrated in European countries with high dependency on natural gas for their energy supply.[104] Germany, France, Italy, the UK, and the Netherlands are testing higher hydrogen concentrations.

In France, the world's first PtG demonstration project, GRYHD, aims to test a 20 percent hydrogen admixture in an existing regional natural gas network serving residences and a medical clinic. In 2018, the GRYHD project began delivering a 6 percent admixture to fuel 100 residents' heaters, hot water tanks, and cook stoves. The demonstration project is moving onto its second phase, incorporating 100 additional homes and admixing up to 20 percent hydrogen.

In the Netherlands, Dutch gas system distribution operators are prohibited from distributing 100 percent hydrogen into the existing gas transportation network. However, the Dutch government is investing in retrofitting existing natural gas transportation pipelines and is supporting demonstration projects. One such project where 100 percent hydrogen has replaced natural gas in existing distribution pipelines is in Rozenburg, a residential neighborhood in Rotterdam. The demonstration project, which began in 2018, involves the entire gas value chain from hydrogen production (via electrolysis) to end use (heating). Green hydrogen is produced nearby and distributed via pipeline to homes where it is burned in central hydrogen boilers.[105]

NOx CONCERNS AND LOW EMISSIONS INNOVATIONS

As discussed earlier, hydrogen combustion—especially hydrogen-blend combustion—can lead to elevated NOx emissions. To avoid this problem, manufacturers are developing ultralow NOx emissions combustion systems that include retrofits for existing installed gas turbines to new flexible-fuel turbines that can burn up to 100 percent hydrogen.[106] These turbine innovations will be supplied across multiple sectors—power generation, home heating, industry, and transportation.

The EU emission standards for NOx are covered by various legal frameworks and regulations. Under its Ecodesign Directive, the European Union has set emissions limits for residential and commercial heating appliances, including boilers and water heaters.[107] Regarding NOx, as

103 Alexandru Floristean et al, "HyLaw: Deliverable 4.1 – Cross Country Comparison," November 3, 2018, https://www.hylaw.eu/sites/default/files/2018-11/D.4.1%20-%20Analysis%20of%20commonalities%20and%20differences%20between%20countries.pdf, (accessed August 30, 2021).

104 Ibid. Dependence on natural gas for primary energy: Netherlands, 42%; Italy, 39%; the UK, 24%; and France, 15%.

105 Johan Knijp, "Heating Dutch homes with hydrogen," *DNV*, December 13, 2019, https://www.dnv.com/oilgas/perspectives/heating-dutch-homes-with-hydrogen.html, (accessed August 30, 2021).

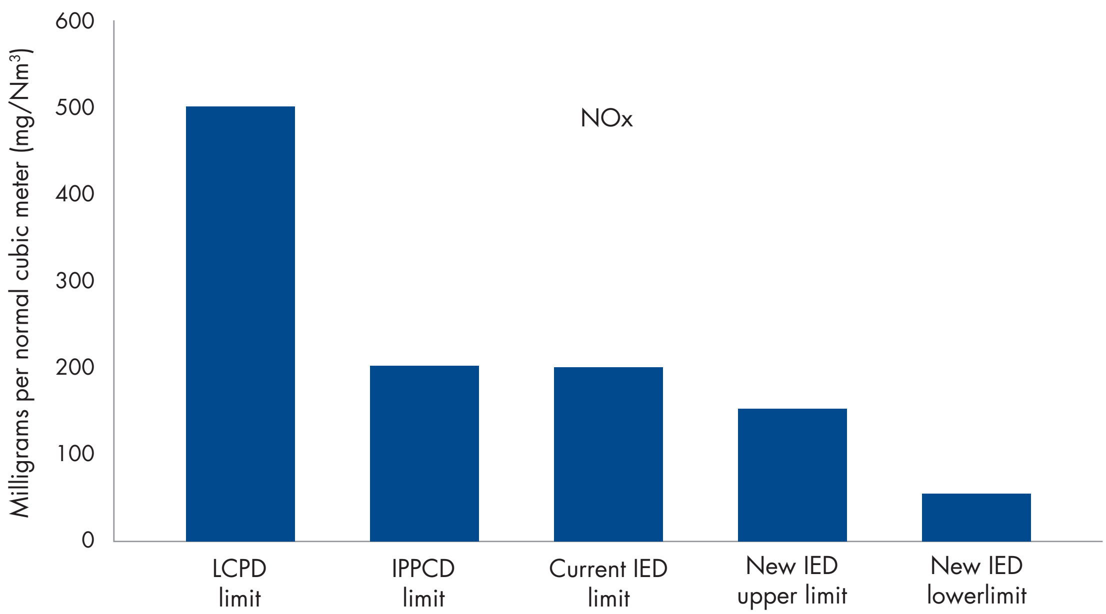
106 Ultralow NOx emissions fall below 9 ppm.

107 There are two classes: energy labeling for below 70 kW and an ecodesign for below 400 kW (split between space and water heaters).

of January 2018, residential heaters may not exceed between 130 mg/kWh-input and 200 mg/kWh-input depending on technology and based on gross calorific value (moisture free).[108]

For large power plants, Europe updated its NOx limits, which came into effect in 2021.[109] The new upper limit for NOx is 85 ppm (175 mg/Nm3); the lower target is 24ppm (50 mg/Nm3).[110,111] (See **Figure 8**.)

FIGURE 8: **Mandated NOx emissions reductions from large coal fired power plants over time**



Since 2001, EU industrial emission policy has reduced NOx emission limits. This graph reflects the mandated reduction in those emissions over time produced by large coal fired power plants.

Notes: LCPD: Large Combustion Plants Directive 2001/80/EC. IPPCD: Integrated Pollution Prevention and Control Directive 2008/1/EC; aspirational non-binding emissions limit. IED: Industrial Emissions Directive 2010/75/EC.

Source: European Environment Agency (EEA)

108 "Commission Regulation (EU) 2015/1188 of 28 April 2015 implementing Directive 2009/125/EC of the European Parliament and of the Council with regard to ecodesign requirements for local space heaters," *EUR-Lex,* April 28, 2015, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A02015R1188-20170109, (accessed September 1, 2021).

109 "Ambitious emission limits for power plants would result in significant pollution cuts in the EU," *European Environment Agency*, December 12, 2018, https://www.eea.europa.eu/highlights/ambitious-emission-limits-for-power, (accessed September 1, 2021).

110 The upper limit represents the minimum target EU Member States must meet; the lower target serves as a reference point for more ambitious reductions. See: "Greening the power sector: benefits of an ambitious implementation of Europe's environment and climate policies," *European Environment Agency*, December 12, 2018; updated April 6, 2021, https://www.eea.europa.eu/publications/greening-the-power-sector-benefits/benefits-of-an-ambitious-implementation, (accessed September 1, 2021).

111 Richard German, "Decomposition analysis for air pollutants and CO_2 emissions from large combustion plants in Europe," *Trinomics*, March 12, 2018, https://www.aether-uk.com/CMSPages/GetFile.aspx?guid=14ca8d73-614e-42db-811d-738425f0b218, (accessed September 1, 2021).

SECTION FIVE

COST AND POLICY BARRIERS AND OBSTACLES

If hydrogen is to be used to decarbonize industry, heating, and transportation, there are several barriers and obstacles that must be overcome. These can be broken down into two main areas:

- Costs—production, electrolyzer capacity, and transport
- Legislative and regulatory policy

COSTS OF PRODUCTION

The biggest barrier to widespread hydrogen adoption is the high cost of producing hydrogen, compared to fossil fuel equivalents. There are different methods of producing hydrogen, with different costs and carbon intensities. Grey hydrogen produced from natural gas without carbon capture is the cheapest form of hydrogen production, but this price does not include any consideration of costs associated with carbon emissions.

Due to the significantly higher costs of green hydrogen compared to grey hydrogen from fossil fuels, consumers have no financial incentive to switch to green hydrogen. To understand how green hydrogen could become cost competitive compared to fossil-fuel equivalents, it is important to consider the key factors affecting the levelized cost of hydrogen (LCOH). The two most significant components of LCOH are renewable electricity cost and electrolyzer capital expenditure (CAPEX).

Electricity cost accounts for 50–70 percent of LCOH while electrolyzer CAPEX accounts for 10–15 percent; the remaining costs can be attributed to hydrogen transportation and storage.[112] The continued reduction in the LCOE of renewable energy and the reduction in electrolyzer CAPEX are key to achieving cost parity with fossil fuels. Both of these costs will be driven by economies of scale and learnings as both the offshore wind industry and hydrogen industry mature.

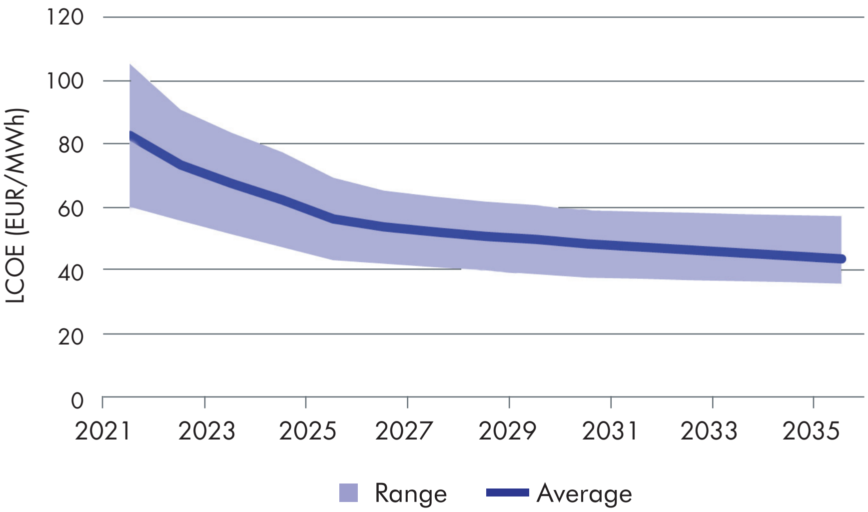
Figure 9 (p. 47) shows the projected decrease in LCOE from offshore wind for fixed foundation projects in Europe.

Figure 10 (p. 48) below shows LCOH in 2021 and 2030 for an onshore electrolyzer plant connected directly to an offshore windfarm, compared with wholesale fossil fuel costs in Europe.

Even in 2030 with significant cost reduction, green hydrogen produced from offshore wind would be more expensive than hydrogen from fossil fuels. In 2030, electrolyzer costs are

112 Based on 2021 costs gathered during industry engagement.

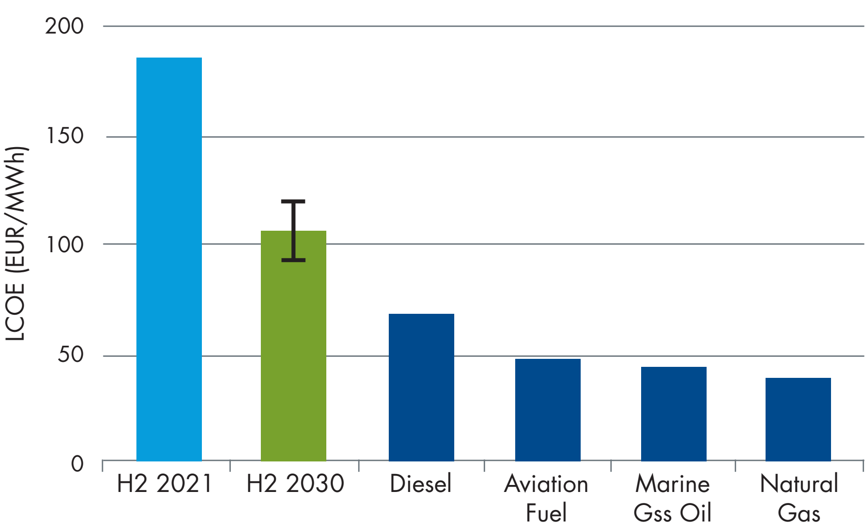
FIGURE 9: **LCOE trajectory for fixed-bottom onshore wind in Europe**



The projected decrease in LCOE for offshore wind for fixed foundation projects in Europe.

Source: BVG Associates

FIGURE 10: **LCOH for green hydrogen for an onshore system connected to offshore windfarm installed in 2021 and 2030 compared with 2021 fossil fuel prices.**



Source: BVG Associates

assumed to fall from \$850/kW in 2021 to \$570/kW and the LCOE of fixed-bottom offshore wind is assumed to fall from \$101/MWh in 2021 to \$59/MWh. Both estimates are wholesale prices excluding any carbon price. Any future carbon taxes levied on fossil fuels could begin to close the price gap between green hydrogen and fossil fuels; however, without carbon taxes, further reduction in LCOE of offshore wind, cost of electrolyzers, or improvements in electrolyzer efficiency, it is unlikely that green hydrogen will be cost competitive with fossil fuels.

It is important to note the impact electricity generation capacity factors have on LCOH. When electrolyzer systems are connected exclusively to renewable generation and the renewable generation is not grid connected, hydrogen output and the LCOH are directly related to the renewable generation project's capacity factor. The higher the capacity factor, the lower the LCOH. Typical capacity factors for the main renewable electricity technologies in Europe are the following: solar PV—20 percent; onshore wind—35 percent; and offshore wind—50 percent.[113]

Offshore wind's high-capacity factor makes it a good match for hydrogen production. An electrolyzer connected exclusively to an offshore windfarm will produce more hydrogen over its life than an electrolyzer connected exclusively to an onshore windfarm or solar PV array of the same generating capacity. However, of the technologies listed above, offshore wind has the highest LCOE, and the benefits

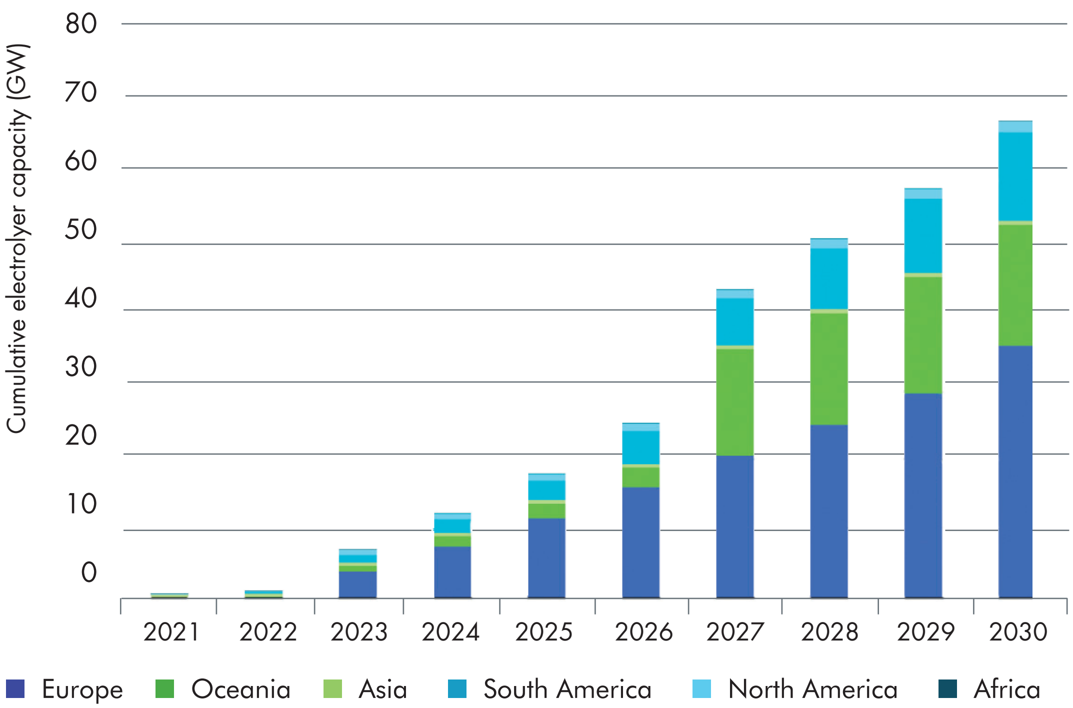
113 Note that capacity factors for renewable technologies vary around the world based on local climatic conditions.

gained by offshore wind's high-capacity factor may be outweighed by its higher LCOE, compared to onshore wind and solar.

ELECTROLYZER DEMAND, SUPPLY, AND COSTS

Based on country targets for electrolyzer capacity, as well as IEA's database of hydrogen projects, BVGA Associates' analysis shows that global electrolyzer capacity will reach nearly 70 GW by 2030 (see **Figure 11**).[114] However, in 2020, Europe had the capacity to manufacture 1.2 GW of electrolyzers per year.[115] Increased capacity is needed if the EU is to achieve its target of 40 GW of electrolyzers by 2030. Gigawatt-scale manufacturing facilities will be needed to ensure the supply of electrolyzers can meet projected demand. However, current electrolyzer costs are approximately $1,000/kW. The EU Fuel Cell and Hydrogen Joint Undertaking has set a target for electrolyzer CAPEX of $600/kW by 2030, while costs as low as $500/kW are being targeted by manufacturers. Electrolyzer manufacturing, installation, operation, and maintenance innovation will result in improved reliability, reduced maintenance costs, and reduced capital costs as investor confidence in electrolyzer technology grows.

FIGURE 11: **Global electrolyer manufacturing capacity forecast to 2030**



Source: BVG Associates

114 "Hydrogen Projects Database," *International Energy Agency*, June 2020, https://www.iea.org/reports/hydrogen-projects-database, (accessed September 1, 2021).

115 "Batteries and hydrogen technology: keys for a clean energy future," *International Energy Agency*, May 3, 2020, https://www.iea.org/articles/batteries-and-hydrogen-technology-keys-for-a-clean-energy-future, (accessed September 1, 2021).

Several reports have identified key areas for electrolyzer stack design development that would provide the desired reduction in LCOH.[116,117,118,119] Different electrolyzer technologies have their own unique technical challenges to overcome but the following key development themes are present across all technologies:

- Reducing membrane and diaphragm thicknesses
- Reducing the quantity of precious metals used such as platinum, iridium, and cobalt
- Increasing current densities
- Improving electrode design with increased area.

The key areas of overall system design and manufacturing that will facilitate reductions in LCOH are:

- Increase size of stack modules
- Increase system size, enabling use of larger, non-bespoke balance of plant equipment (such as water treatment systems, power electronics, gas conditioning, and compressors), and
- Development of GW-scale manufacturing facilities using serial, automated manufacturing processes.

In 2021, ITM Power began operating the first electrolyzer production line at its new "giga-factory," which will eventually be capable of producing 1 GW of electrolyzers per year.[120] Nel, a Norwegian electrolyzer manufacturer, has announced a new 500 MW production line that will begin operating by the end of 2021, with the aim to increase this to a total capacity of 2 GW per year.[121] Both projects are targeting a 40 percent reduction in electrolysis capital costs based on production capacity of 500 MW/year, and Nel is targeting a further reduction to $300/kW as electrolysis capacity grows to 2 GW/year.

116 "Green Hydrogen Cost Reduction: Scaling Up Electrolysers to Meet the 1.5℃ Climate Goal," *International Renewable Energy Agency*, 2020, https://irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf, (accessed September 1, 2021).

117 Angeliki Spyroudi et al, "Offshore Wind and Hydrogen: Solving the Integration Challenge," *Offshore Wind Industry Council* and *Offshore Renewable Energy Catapult*. September 2020, https://ore.catapult.org.uk/wp-content/uploads/2020/09/Solving-the-Integration-Challenge-ORE-Catapultr.pdf, (accessed September 1, 2021).

118 O. Schmidt et al, "Few, Future cost and performance of water electrolysis: An expert elicitation study," *International Journal of Hydrogen Energy*, Volume 42; Issue 52, December 28, 2017, https://www.sciencedirect.com/science/article/pii/S0360319917339435, (accessed September 1, 2021).

119 "Gigastack: Bulk Supply of Renewable Hydrogen," *Element Energy Limited*. January 2020, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/866377/Phase_1_-_ITM_-_Gigastack.pdf, (accessed September 2, 2021).

120 Leigh Collins, "Green hydrogen: ITM Power's new gigafactory will cut costs of electrolysers by almost 40%," *Recharge*, January 20, 2010; updated February 10, 2021, https://www.rechargenews.com/energy-transition/green-hydrogen-itm-power-s-new-gigafactory-will-cut-costs-of-electrolysers-by-almost-40-/2-1-948190, (assessed September 2, 2021).

121 James Burgess, "Norway's Nel Q1 hydrogen electrolyzer sales hit by pandemic," *S&P Global*, May 4, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/050421-norways-nel-q1-hydrogen-electrolyzer-sales-hit-by-pandemic, (accessed September 2, 2021).

HYDROGEN TRANSPORT

Hydrogen transportation adds significant cost to the LCOH. There are three main methods of bulk hydrogen transportation: pipeline, hydrogen tanker vessel, and ammonia tanker vessel.

Transport of hydrogen in bespoke steel pipelines has been demonstrated in many countries around the world. Such systems are purpose built and can, through careful material choice and pipeline design, mitigate some of the maintenance issues associated with pipeline transportation of hydrogen, such as embrittlement leading to cracks, and the high permeability of hydrogen. However, these systems are not used for long distance transportation of hydrogen across countries and are commonly used to distribute hydrogen to local industrial sites.

Proposals to re-purpose existing gas networks have technical challenges. The suitability of existing pipeline material to transport hydrogen is not fully understood and work is needed to characterize the suitability of gas networks in different locations. Additionally, other components of the pipeline systems, such as valves, seals, fittings, pressure regulators, metering equipment, and safety equipment, may need to be replaced to be suitable for operation with pure hydrogen due to the higher permeability of hydrogen compared with natural gas.[122]

Hydrogen compression is another key challenge to pipeline distribution of hydrogen. To capture 80–90 percent of pure hydrogen's energy, purpose-built hydrogen compressors are needed. The compressors and the energy needed to achieve high compression levels increase costs.[123] Improvements in the efficiency of these compressors will be important to limiting transportation costs for hydrogen.

Unlike pipeline transportation of hydrogen, transportation of hydrogen via liquefied hydrogen tanker vessel or compressed hydrogen tanker vessel are new concepts in early demonstration phase.

Kawasaki Heavy Industries has developed the world's first liquefied hydrogen carrier, the Suiso Frontier, which transports hydrogen at temperatures of –253°C. The liquefaction process for hydrogen is energy intensive, consuming almost 30 percent of the energy stored.[124] This system is currently being demonstrated, transporting hydrogen from Australia to Japan in the HySTRA project.[125]

Liquefied hydrogen carriers (LHCs) are similar to liquefied natural gas (LNG) carriers, however LHCs operate at much lower temperatures: –253°C compared to –162°C, respectively. The low temperature is required to maximize the volumetric density of hydrogen and reduce the size of the carrier required to transport a given quantity of hydrogen.

122 Hydrogen is a small molecule that can leak through many materials, including rubber and some steel, and can escape through improperly sealed pipeline joints.

123 Bent Sorensen and Giuseppe Spazzafumo, "Hydrogen and Fuel Cells, Third Edition," *Academic Press*, February 10, 2018, https://www.elsevier.com/books/hydrogen-and-fuel-cells/sorensen-sorensen/978-0-08-100708-2?, (accessed September 2, 2021).

124 Ibid.

125 "Hydrogen Supply Chain: Hydrogen Energy Supply Chain Pilot Project between Australia and Japan," *CO_2-free Hydrogen Energy Supply-chain Technology Research Association,* http://www.hystra.or.ip/en, (accessed August 3, 2021).

The low temperature requirement introduces challenges for liquefied hydrogen transport. Any heat gain results in hydrogen boil-off: a loss of hydrogen to the atmosphere. To prevent this, hydrogen containers are designed to minimise heat gain from the environment, using vacuum-insulated double walled containers. These liquid hydrogen containers are more costly when compared to equivalent LNG tankers.

There is uncertainty in the cost of LHC transportation. One assessment of the cost of LHC transportation is $0.45/kgH2, with the primary cost component being the value of lost hydrogen through boil-off.[126] Other studies estimate the cost of LHC transportation to be between $1.00–1.40/kgH2.[127] Compressed gas hydrogen tanker transportation is at an earlier stage in development. It is a less popular a choice for long-distance hydrogen transportation due to the lower volumetric energy density compared to liquid hydrogen transportation. However, unlike liquid hydrogen carriers, compressed hydrogen is stored at ambient temperature and results in lower losses. This may make compressed hydrogen carriers more suitable for long-distance hydrogen transport. Global Energy Ventures is currently developing a compressed gas hydrogen tanker, which would store hydrogen at 3,625 psig.[128]

The viability of both liquid hydrogen and compressed hydrogen tanker transportation is yet to be proven at scale. Investment into research and development of these technologies, as well as demonstration of the end-to-end systems, will need to be undertaken before either technology reaches maturity. Key to this will be minimizing energy losses from compression or liquefaction, and losses from storage containers during transportation.

Another option for transporting hydrogen is via ammonia. Conversion of hydrogen to ammonia via the Haber-Bosch process is a mature process used around the world to produce ammonia as feedstock for fertiliser production and production of other chemical products. Transport of ammonia via refrigerated tankers is also well established, with a network of onshore storage facilities, port facilities, and shipping routes in operation around the world.

Ammonia is stored at lower temperature and pressure than hydrogen and thus requires less energy for cooling and compression. Liquid ammonia has a higher energy density than either liquid or compressed hydrogen (see **Table 1**). These factors result in lower overall shipping costs for ammonia. Ammonia can be used directly as fuel or fertilizer and can also be converted back to hydrogen.

TABLE 1: **Volumetric energy density of liquid ammonia, liquid hydrogen, and compressed hydrogen.**

Fuel	Volumetric energy density (MWh/m^3)
Liquid hydrogen	2.6
Compressed hydrogen (700 bar)	1.9
Liquid ammonia (-35°C)	3.5

126 Mohommed Al-Breiki and Yusuf Bicer, "Comparative cost assessment of sustainable energy carriers produced from natural gas accounting for boil-off gas and social cost of carbon," *Energy Reports*, Volume 6, November 2020, https://www.sciencedirect.com/science/article/pii/S2352484720312312, (accessed August 27, 2021).

127 "Ammonia: zero-carbon fertiliser, fuel and energy store," Policy Briefing, *The Royal Society*, 2020, https://royalsociety.org/-/media/policy/projects/green-ammonia/green-ammonia-policy-briefing.pdf, (accessed August 25, 2021).

128 "Hydrogen: Transporting the future of energy as C-H2," *Global Energy Ventures*, https://gev.com/hydrogen, (accessed August 3, 2021).

LEGISLATION AND REGULATION

There are few legislative and regulatory barriers in Europe to the roll-out of green hydrogen technologies. Legislation supporting green hydrogen production and clearer regulations on development planning, ownership, and operation of hydrogen assets including hydrogen pipelines, as well as new design standards covering emerging hydrogen technologies can support the scale-up of green hydrogen.

Gas Network Regulation

Current limits on the allowed percentage of hydrogen by volume blended in gas networks could impact future adoption of green hydrogen. Limits on blending would need to be relaxed, and new regulations relating to safe use of pure hydrogen in buildings and homes would need to be created to bring green hydrogen to scale. Furthermore, blending limits across integrated gas networks will need to be aligned and to enable cross-border trade.

New gas metering, network tariffs, and payments process must be put in place to ensure that there are clear and consistent rules for green hydrogen grid injection.

End-User Application Standards

Design standards for end-use applications, particularly domestic applications, are required before large-scale roll out of hydrogen usage in homes can occur. This relies on well-defined gas network specifications, with known percentage blends of hydrogen, as this will impact the calorific value of the gas, combustion properties, and heating characteristics, which will all impact the design and operation of end use appliances.

Standards are also needed to ensure appliance safety. Trials are ongoing in many European countries to demonstrate safe use of hydrogen appliances, the results of which will form the basis of new standards and regulations.

Electricity Network Regulations

A benefit of electrolyzers is their ability to provide grid balancing services. Regulations relating to the provision of grid balancing and flexibility services should appropriately accommodate electrolyzers, allowing them to compete for services on a level playing field.

The HyLaw project funded by the EU Fuel Cells and Hydrogen 2 Joint Undertaking will identify legal and regulatory barriers.[129]

COSTS VS DEMAND FOR HYDROGEN

Perhaps the most crucial obstacle for the hydrogen industry to overcome is the chicken-and-egg scenario in which it presently finds itself. To achieve cost competitiveness with fossil fuels requires economies of scale and learning. Large-scale deployment of green hydrogen production requires a large demand for green hydrogen, which will only be achieved when green hydrogen is competitive economically with fossil fuels or if the price is supported by government.

In the next section, drivers and key policy enablers are discussed, which have the potential to mitigate and overcome the barriers and obstacles discussed in this section.

129 "Info Centre," *HyLaw*, https://www.hylaw.eu/info-centre, (accessed August 3, 2021).

SECTION SIX

HYDROGEN ENABLERS AND DRIVERS

Green hydrogen in Europe has three main drivers and enablers: carbon reductions, cost competitiveness, and public policy.

PUBLIC POLICY

European governments could implement a range of policies to overcome many of the cost, technology, and regulatory barriers limiting the uptake of green hydrogen. The continued cost reduction of offshore wind, as well as other renewables, will be key to driving down the cost of green hydrogen. Therefore, policies enabling continued deployment and cost reduction of offshore wind will be important.

Enabling supply and demand of hydrogen are closely linked, and policies should be a part of cohesive hydrogen strategies. For the purposes of discussion, policies have been separated into three sections:

- Policies enabling green hydrogen supply
- Policies enabling hydrogen demand, and
- Policies enabling offshore wind deployment.

Policies Enabling Green Hydrogen Supply

Setting targets for green hydrogen production will contribute to market certainty and encourage commercial investment. Many countries around the world have set targets for installed electrolyzer capacity by 2030, including UK, Germany, France, the Netherlands, Portugal, and Chile.

Establishing a competitive market support mechanism. In the near-to-medium term, green hydrogen will not reach cost parity with fossil fuels. A market support mechanism such as a Renewable Energy Certificate or Contract for Difference can guarantee green hydrogen producers a price for hydrogen, enabling investment in new green hydrogen production and allowing end users to replace their fossil fuels with green hydrogen at no additional cost. Although price support mechanisms can be implemented without a competitive element, competitive auctions have proven to result in significant reductions in LCOE for other renewable generation technologies. Competition between developers of hydrogen production projects will likely result in quick learning, innovations, and reductions in LCOH.

Establish funding sources for demonstration projects. Demonstration projects are important tools for testing multiple system concepts and business models for hydrogen production, identifying any issues and opportunities at a small scale, which can be resolved before deployment at large scale. These projects are inherently risky and accessing funding can be difficult. Government sources of funding can enable early demonstration projects.

Increase support for research and development. Innovations in design and installation of the full hydrogen supply chain are needed to reduce LCOH. Investment in R&D in the private sector and academic sector will be needed to drive forward this innovation.

Support for local supply chain development including construction of large-scale serial manufacturing facilities for electrolyzer systems.

Implementations of standards and regulations that are aligned with ambitions to increase green hydrogen production. This will include safety standards for hydrogen in non-industrial settings such as domestic buildings, planning guidance for new hydrogen production and distribution facilities, and clear rules regarding the ownership of hydrogen production and distribution infrastructure.

Establishment of a hydrogen-origin certification scheme. To ensure the integrity of green hydrogen's carbon-saving credentials in a global market, it is vital that a certification scheme that authenticates the source of hydrogen is implemented and ensures there is a clear differentiation between green hydrogen and hydrogen produced from fossil fuel sources.

Policies Enabling Green Hydrogen Demand

Setting targets for green hydrogen use in individual sectors. Establishing government targets will give the market increased certainty and encourage private investment. Hydrogen end-use demands are varied and individual targets could be established across the different heat, transportation, and industry sectors, with specific roadmaps for how those targets will be achieved. Governments including Japan, Korea, the Netherlands, and Germany have established targets for the number of fuel cell electric vehicles and hydrogen refueling stations.[130] These are examples of target setting which can initiate private investment.

Funding local hydrogen hub infrastructure projects. Hydrogen hubs are joint multiple-stakeholder projects where partners work together to develop a full hydrogen system comprising production, distribution, and end use. Hydrogen hubs allow demonstration of multiple technologies and business models, as well as allow incremental expansion of a hydrogen network around the central hub. Hubs offer a low-risk, small-scale launch pad for hydrogen systems.

Implement tax incentives to encourage uptake of end-use technologies. Tax incentives can be used to reduce the cost of new equipment to end users and encourage uptake. Elimination of sales and import taxes on hydrogen equipment, or tax credits offsetting the purchase cost of new equipment from corporate tax bills, can incent uptake of end-use hydrogen equipment.

Policies Enabling Offshore Wind

In addition to scaling up electrolyzer capacity and supporting the industry with public policy and support schemes, policies driving offshore wind cost reductions are key not only to green hydrogen cost reductions, but also to realizing green hydrogen at scale. The following is a list of green hydrogen-enabling policies in effect in Europe.

130 Jose M. Bermudez and Taku Hasegawa, "Hydrogen: Tracking Report – June 2020," *International Energy Agency*, June 2020, https://www.iea.org/reports/hydrogen, (accessed August 24, 2021).

- **Implementation of competitive auctions for offshore wind projects.** The shift in Germany and the UK to competitive auctions has contributed to a 60 percent reduction in five years in projects' LCOE.[131]
- **Setting targets for offshore wind deployment to give industry confidence in future pipeline and unlocking investment.** A predictable, large and stable market provides confidence to investors and lowers project risk and LCOE.
- **Implementation of aligned policies and procedures, specifically relating to seabed leasing, permitting, interconnection, and auctions.** This enables long-term planning and attracts more developers to the market.
- **Investment in coastal infrastructure such as ports and port-side manufacturing.** Good coastal infrastructure in good locations reduces logistics costs, project risk, and ultimately LCOE.

CARBON REDUCTION

The vast majority of global hydrogen production (2,400 TWh) is produced from gas reformation without the use of carbon capture. It is estimated that hydrogen produced from gas reformation has a carbon intensity of 350 $kgCO_2e/MWh$, resulting in 810 million tons of CO_2e emissions every year. (See **Figure 12**, p. 56.)[133] Even with implementation of carbon capture and storage technology alongside steam methane reformation, blue hydrogen's carbon intensity is still estimated to be 100$kgCO_2/MWh$ due to CO_2 and methane leaks.[132]

If the fuels shown in **Figure 12** are replaced by green hydrogen, hundreds of kilograms of CO_2 equivalent emission savings per MWh of fuel replaced could be achieved.[134]

COST COMPETITIVENESS

Although there is a clear carbon emission saving proposition for green hydrogen, the financial proposition for green hydrogen remains weak. The impact of government policy on the financial proposition of green hydrogen will be significant. **Figure 10** (p. 47) shows that by 2030 green hydrogen produced from offshore wind will not be cost competitive with wholesale, pre-tax, fossil fuels. Increased taxation of fossil fuels will reduce the gap between green hydrogen and fossil fuels. Analysis carried out on behalf of the Scottish Government showed that green hydrogen could be cost competitive against fuels with the highest taxation levels such as road fuels by 2032 with green hydrogen achieving cost parity with gas at £7.80/kg ($10.75/kg) and with diesel for trains at £3.40/kg ($4.64/kg).[135]

131 The overall reduction of 60 percent is based on bid prices. Industry feedback is that auctions have been the biggest factor driving cost reduction. They have driven accelerated learning, innovation and collaboration through the supply chain. In each market, there are different drivers at work.

132 "Hydrogen in a low-carbon economy," *Committee on Climate Change*, November 22, 2018, https://www.theccc.org.uk/publication/hydrogen-in-a-low-carbon-economy, (accessed August 27, 2021).

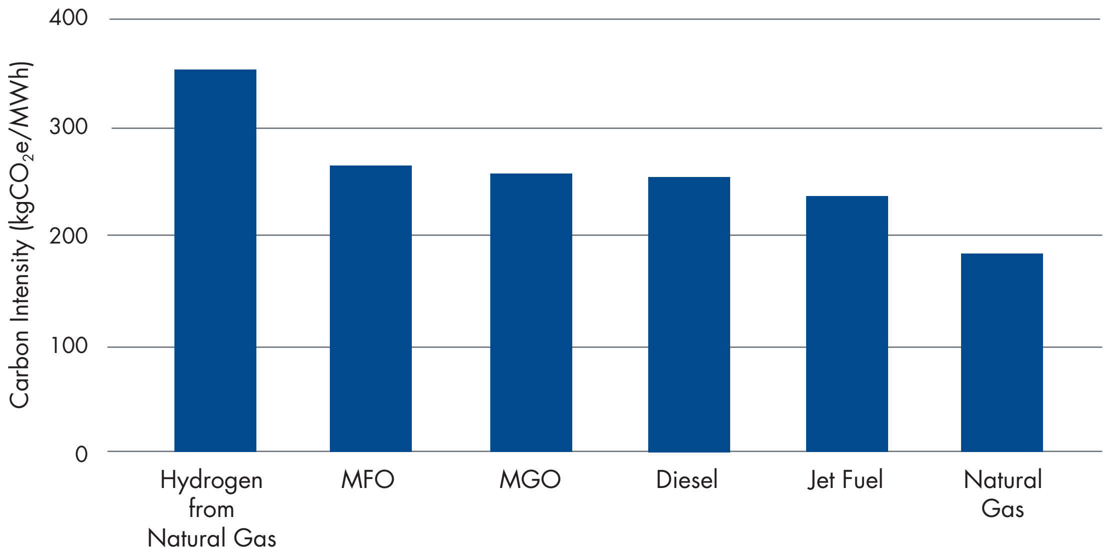
133 "Greenhouse gas reporting: conversion factors 2020," *UK Government, Department for Business, Energy & Industrial Strategy*, June 9, 2020, https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2020, (accessed September 1, 2021).

134 We have not calculated the embedded carbon intensity of green hydrogen, but it is likely to be negligible.

135 "Offshore wind to green hydrogen: opportunity assessment," *Scottish Government, Energy and Climate Change Directorate*, Pages 38-47, December 21, 2020, https://www.gov.scot/publications/scottish-offshore-wind-green-hydrogen-opportunity-assessment, (accessed September 3, 2021).

The cost gap will be reduced further by cost reductions achieved through investments in research, development, and manufacturing, as well as learning through deployment.

FIGURE 12: **Carbon intensity of hydrogen produced from steam methane reformation compared with carbon intensities of fossil fuels.**



Of the fuels assessed, hydrogen produced from natural gas has the highest carbon intensity, followed by marine fuel oil (MFO), marine gas oil (MGO), automotive diesel, and jet fuel.

Source: BVG Associates

SECTION SEVEN

OFFSHORE WIND TO GREEN HYDROGEN FOR THE U.S.

This paper has focused on the current situation in Europe. For the United States, it may ultimately make sense to use some offshore wind output for hydrogen production. This will be especially true in situations where excess offshore wind can be transformed into green hydrogen, thereby reducing curtailment and producing green hydrogen when the cost of electricity is cheapest, or where interconnection congestion and limited landing sites delay or prohibit cable landings. In these cases, PtG can offer system integration benefits and can cost-effectively deliver offshore wind energy.

However, it must be recognized that the US offshore wind industry is at a much earlier stage of development than the European industry. The output from the initial US wind farms will be fully needed for electricity production that displaces fossil fuel generation. That electricity will be especially valuable because the wind farms will be in relatively close proximity to major load centers, such as the New York metropolitan area, eastern Massachusetts, and the Baltimore region. Until there has been significant offshore wind development in the US, it will not make sense to divert output to hydrogen production. Europe is, in part, focusing on offshore wind to hydrogen because offshore wind farms are being planned for locations far from major load centers and where there will be difficulty integrating some of the output into the electric grid. Green hydrogen is also a key component of Europe's deep decarbonization strategy for sectors where electrification is technologically unfeasible.

Despite offshore wind to hydrogen being on a slower trajectory than in Europe, it does not mean that the US federal government and the states should ignore the potential for green hydrogen. Research into hydrogen technologies and applications should continue, especially to ensure that any future expanded hydrogen use does not cause unforeseen environmental or economic problems. For offshore wind in particular, research should identify what needs to be done over the coming decade to prepare for possible use of excess offshore wind output for green hydrogen sometime after 2030.

Furthermore, states could prepare roadmaps for green hydrogen development, including electrolyzer and fuel cell targets. State policies and incentives can support hydrogen and fuel cell deployment and create jobs throughout the supply chain. The Northeast has both a strong offshore wind resource and a strong hydrogen fuel cell supply chain, especially in New York and Connecticut.

States could also enter into partnerships with the US Department of Energy or its national labs to study potential hydrogen applications and technologies. Research partnerships that improve electrolyzer efficiencies, safe hydrogen transportation and storage, and explore potential applications across a variety of sectors would help states better understand hydrogen's applicability in economy-wide decarbonization.

In addition, it will be imperative for states to engage stakeholders, including environmental justice and community-based organizations, in dialogue and discussion on green hydrogen's potential applications and pathways. Stakeholder engagement should occur prior to any decisions on demonstration projects or publication of roadmaps. This is especially true for any potential combustion of green hydrogen for power generation as fossil fuel power plants are often located in frontline communities. Even with low NOx technologies, the continued existence of power plants in under-resourced communities will impact health, property values, and more.

Separate from offshore wind, some well-chosen, small, green hydrogen pilot projects will make sense. Policies can be assessed and implemented to address some of the technical and cost barriers to hydrogen, and to ensure that green hydrogen will ultimately be used to decarbonize hard-to-electrify sectors rather than to extend the life of fossil fuel power plants. Some fossil fuel companies and utilities are using the long-term vision of a hydrogen future as a rationale for building more natural gas generators and perpetuating existing fossil fuel technologies; states and the federal government should make sure that that does not happen.

In addition, as this paper shows, it will be important for policymakers and the energy industry in the US to continue to closely monitor what is going on in Europe with hydrogen.

APPENDIX

FOUR CASE STUDIES

Below we include four extensive case studies that take a closer look at the opportunities and challenges Europe faces as it seeks to bring green hydrogen to full commercial scale. The case studies cover Europe's hydrogen strategy—the hydrogen rollout roadmap driving green hydrogen's development across the European Union; Denmark's unique offshore wind-to-hydrogen proposition; hydrogen's role in Germany's energy transition; and various examples of projects under development.

CASE STUDY 1

European Union's Hydrogen Strategy

Background

In 2020, the EU released the *"Hydrogen Strategy for a Climate Neutral Europe,"* a strategic roadmap that outlines the bloc's efforts to accelerate green hydrogen within its member states.[136] Hydrogen currently accounts for less than 2 percent of the EU's energy consumption,[137] with green hydrogen comprising an even smaller fraction of the EU's energy mix.[138] Hydrogen is primarily used in the EU as feedstock for industrial processes like ammonia and methanol production. Hydrogen infrastructure is also sparse, with only 5,000 kilometers of hydrogen pipelines to date.[139] To accelerate and fully decarbonize its economy, the EU is driving significant investment and implementing legal frameworks in green hydrogen.

The EU, which accounted for roughly 10 percent of global CO_2 emissions in 2019, has committed significant financial and political resources to accelerating progress towards a low-carbon economy.[140,141] In the wake of the COVID-19 crisis, the European Union (EU) stressed an urgent need for countries to "build back better" through post-pandemic green stimulus efforts, including a wide-ranging portfolio of mitigation and adaptation measures to combat

136 "Hydrogen Europe Vision on the Role of Hydrogen and Gas Infrastructure on the Road Toward a Climate Neutral Economy," *Hydrogen Europe Secretariat*, April 2019, https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf, (accessed August 23, 2021).

137 Gregor Erbach and Liselotte Jensen, "EU hydrogen policy Hydrogen as an energy carrier for a climate-neutral economy," *European Parliamentary Research Service*, April 2021, https://www.europarl.europa.eu/RegData/etudes/BRIE/2021/689332/EPRS_BRI(2021)689332_EN.pdf, (accessed August 30, 2021).

138 Ibid, Erbach and Jensen. Ninety-six percent (96%) of this grey hydrogen is produced from fossil fuel-intensive processes like steam methane reforming.

139 Ibid, Erbach and Jensen.

140 "Carbon dioxide (CO_2) emissions in the European Union from 1965 to 2020 (in million metric tons of CO_2)," *Statista*, 2021, https://www.statista.com/statistics/450017/co2-emissions-europe-eurasia, (accessed September 7, 2021).

141 "Global CO_2 emissions in 2019," *International Energy Agency*, February 11, 2020, https://www.iea.org/articles/global-co2-emissions-in-2019, (accessed August 31, 2021).

climate change. In 2021, the EU established legally binding targets for the bloc to achieve carbon emissions reductions of 55 percent by 2030 compared to 1990 levels, one of the most ambitious decarbonization commitments made by a large economy to date. These targets are part of a broader climate action strategy known as the European Green Deal,[142] which includes policies and investments to support an economy-wide "just" transition to climate neutrality by 2050.

The EU recognizes the importance of accelerating decarbonization efforts not only for its electricity and transportation sectors, but also for its industrial sector, which includes the production of iron, steel, cement, chemicals, and other carbon-intensive manufacturing processes. Yet, significant challenges remain for the decarbonizing of industry. For these "hard-to-abate" sectors, where traditional solutions like electrification may not be feasible, green hydrogen is poised to play an important role in the energy transition. However, absent further public- and private-sector investment in enabling green hydrogen infrastructure to reduce implementation barriers and costs, green hydrogen's impact on the EU's efforts will remain limited.

Targets and Ambitions

The EU views green hydrogen as a major opportunity to establish international leadership on efforts to combat climate change and is eager to capitalize on its opportunity to develop a robust green hydrogen market. The EU also has significant capacity for innovation and deployment of green hydrogen technology at scale, including a wealth of renewable energy resources, research and innovation hubs, and government support through robust policy measures. In 2020, the EU established goals to substantially expand its green hydrogen capabilities by installing 6 GW and 40 GW of green hydrogen electrolyzers and yielding 1 million tons and 10 million tons of green hydrogen by 2024 and 2030, respectively.

Current State of Hydrogen

Hydrogen currently plays a minor role in the EU's energy sector; it is largely produced from fossil-fuel-based resources and is not yet cost competitive with fossil-fuel-based alternatives.

The drivers of supply and demand for hydrogen ultimately vary on a country-by-country basis within the EU. For some countries that are significant producers of renewable energy like Denmark, green hydrogen presents an economically attractive solution on the supply side. For other countries with carbon-intensive industrial sectors like Germany, green hydrogen remains a critical solution to achieve decarbonization goals on the demand side. Government policies also vary by country. While some countries have developed their own national green hydrogen strategies or are currently in the process of doing so, others have lagged behind. However, the EU and its member states have increasingly understood the importance of such policy measures to accelerate the development and deployment of green hydrogen and recognized the value of cross-country, cross-sector collaboration on green hydrogen.

Proposed Hydrogen Strategy

The EU faces a range of opportunities and challenges as it seeks to advance its green hydrogen strategy. There exists an urgent need for the EU to facilitate energy system integration, or the connecting of sources of energy production with sources of energy consumption by both

142 "A European Green Deal," *European Commission*, https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en, (accessed August 23, 2021).

utilizing existing infrastructure and deploying new infrastructure to support green hydrogen adoption.

In 2020, the EU released a *"hydrogen strategy for a climate neutral Europe,"*[143] a strategic roadmap that outlines the bloc's efforts to accelerate green hydrogen within its member states. Articulating that green hydrogen will play an essential role in the EU's transition to a climate neutral economy, the roadmap indicates a host of benefits of green hydrogen for the EU, including environmental benefits (particularly for hard-to-abate sectors) and economic benefits (particularly regarding substantial job growth), with robust applications across a range of sectors. The EU's analysis projects that green hydrogen could account for nearly €500 billion of investment, over 1 million jobs, and upwards of 13 percent of Europe's energy mix by 2050. Despite previous hype surrounding green hydrogen that did not materialize, the current momentum presents a new opportunity: the costs of renewable energy have significantly declined, technology has substantially improved, and stakeholders have increasingly rallied around the need for global decarbonization.

The EU's green hydrogen roadmap articulates a multi-pronged strategic approach to green hydrogen development. Core to the EU's strategy is a phased approach, one that involves expanding low-carbon hydrogen resources, such as blue hydrogen (or hydrogen generated from fossil-fuel sources combined with carbon capture and storage), while developing green hydrogen until it becomes cost-competitive with fossil-based hydrogen. The EU's strategy consists of three phases, spanning the 2020 to 2024 (Phase 1), 2025 to 2030 (Phase 2), and 2030 to 2050 (Phase 3) timeframes.

During Phase 1, from 2020 to 2024, the EU is primarily focused on expanding green hydrogen electrolyzer technologies, decarbonizing existing hydrogen production, and expanding hydrogen production for applications in carbon-intensive industries on the technology side, while developing regulatory frameworks to incentivize green hydrogen production and consumption, supporting green hydrogen infrastructure, and developing investment mechanisms on the policy side. During Phase 2, the EU aims to significantly accelerate green hydrogen cost curves and deployment of green hydrogen technologies and infrastructure through strategic integration of energy infrastructure networks, deployment of large-scale hydrogen production and storage facilities, and development of competitive markets for green hydrogen. Lastly, during Phase 3, the EU intends to substantially ramp up its green hydrogen deployment at scale and significantly expand its renewable energy resources once green hydrogen becomes economically viable.

Barriers

Yet the report also recognizes significant challenges and barriers that the EU currently faces on its path towards accelerating green hydrogen. Analysis from Brink News finds that key obstacles that the EU must currently address to accelerate green hydrogen deployment include electricity costs,[144] which comprise 70 percent of the overall cost of green hydrogen, deployment

143 "A hydrogen strategy for a climate-neutral Europe," *Communication from The Commission to The European Parliament, The Council, The European Economic and Social Committee and The Committee of The Regions*, August 7, 2020, https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf, (accessed September 3, 2021).

144 Constantine Levoyannis, "Can the EU Successfully Build a Hydrogen Economy?" *Marsh McLennan*, February 11, 2021, https://www.brinknews.com/can-the-eu-successfully-build-a-hydrogen-economy, (accessed September 2, 2021).

of enabling hydrogen infrastructure, and transportation and distribution networks to link the supply of green hydrogen to the sources of greatest demand. Strategies for accelerating green hydrogen deployment will vary on a country-by-country basis. For example, the EU can address renewable electricity costs by focusing on regions with low-cost renewable energy such as Denmark, with its robust offshore wind resources. The EU also must make unprecedented investments in technologies and infrastructure to support the rapid and cost-effective development of green hydrogen.

Policy, Technology, and Investments

Over the next several decades, the EU will need to accelerate a series of technology, policy, investment, and research and development measures that involve a range of considerations, including geopolitical, value chain, cost-effectiveness, and competitiveness impacts. Technology strategies include repurposing existing infrastructure for green hydrogen and exploring blending of hydrogen in existing natural gas pipelines. Policy strategies include incentivizing green hydrogen on both the supply and demand sides, developing standards and taxonomies surrounding green hydrogen, creating fair competitive markets for hydrogen, streamlining project approval and permitting processes, and exploring integration of green hydrogen strategies with existing and proposed policies like the EU's Emissions Trading Scheme (ETS) and potential carbon border adjustment mechanisms. Investment strategies include private sector investment and collaboration with development banks and other financial institutions to accelerate investment in hydrogen production, transportation, distribution, storage, refueling, and other forms of enabling infrastructure. Lastly, research and development efforts, such as developing more cost-effective electrolyzers, improving green hydrogen technology and infrastructure, diversifying end-use applications, and deepening the understanding of safety and materiality impacts, will play a critical role throughout all three phases to support large-scale, high-impact green hydrogen projects across the value chain.

The EU has pursued a series of policies and investments to support the development of green hydrogen within the bloc thus far. These measures include the Trans-European Networks for Energy,[145] which focuses on integrating the energy infrastructure of different EU countries by identifying strategic corridors and areas of collaboration, and the Connecting Europe Facility,[146] which provides a vehicle for funding energy infrastructure projects in the EU. Furthermore, the EU has assembled a series of formal and informal workshops and groups, including the Hydrogen Energy Network,[147] which consists of a range of energy representatives from EU countries to share best practices and collaborate on initiatives regarding hydrogen and energy development, as well as the European Clean Hydrogen Alliance,[148] which convenes a range of public and private sector stakeholders to advance development and deployment of green hydrogen technologies. As of 2020, over 1 GW of electrolyzer projects already exist in the current pipeline and more than 280 companies are involved in green hydrogen development and deployment efforts.

145 "Trans-European Networks for Energy," *European Commission*, Published: 5 April 2017; Last update: 5 July 2021, https://ec.europa.eu/energy/topics/infrastructure/trans-european-networks-energy_en, (accessed August 21, 2021).

146 "Connecting Europe Facility," *European Commission*. https://ec.europa.eu/inea/en/connecting-europe-facility, (accessed August 23, 2021).

147 "Hydrogen Energy Network meetings," *European Commission*, https://ec.europa.eu/energy/topics/energy-system-integration/hydrogen/hydrogen-energy-network-meetings_en, (accessed August 23, 2021).

148 "European Clean Hydrogen Alliance," *European Commission*, https://ec.europa.eu/growth/industry/policy/european-clean-hydrogen-alliance_en, (accessed August 23, 2021).

Existing and Planned Projects

A host of green hydrogen projects have been proposed in the EU, with many already in the development phase. In April 2021, bp, Iberdrola, and Enagás announced a partnership to develop a green hydrogen project in a bp refinery in Castellón, Spain,[149] which would consist of a 20 MW electrolyzer project that would potentially scale up to 115 MW, as well as an accompanying 40 MW solar photovoltaic plant. The green hydrogen project would offset the emissions of the existing bp refinery. If completed, the project would become one of Spain's largest green hydrogen projects, offering a prime example of how the EU can utilize green hydrogen to support its decarbonization strategy.

CASE STUDY 2

Denmark's Offshore Wind to H2 proposition

Background

Denmark is deeply committed to being a global leader on climate and energy issues. As a small country that has already taken bold action in transforming its energy supply and reducing its emissions, Denmark is keen to advance its climate solutions and innovations across the globe. The country is well on the road to decarbonization of its electric sector. Nearly 80 percent of its electricity supply comes from renewables (47 percent directly from wind) and renewables contribute to approximately 35 percent of total energy consumption.[150]

The Danish Parliament enacted the national *Climate Act* in 2019 to be fossil-fuel free by 2050. This legally binding act commits Denmark to reducing its greenhouse gas emissions by 70 percent by 2030, compared to 1990 levels.[151] By 2050, Denmark will have transitioned to 100 percent renewable energy. This ambitious 2050 target is the goal of the "moon-landing project," so named for its scale of ambition. To reach this goal, Denmark will continue pursuing electrification of buildings, industry, and transportation and will invest in green hydrogen and PtX to decarbonize the 30–40 percent of its economy that is challenging to electrify.

Denmark launched its first offshore wind project in 1991. As a result of its leadership, offshore wind and other renewable energy technologies have become cost competitive with fossil fuels over the last thirty years in Denmark. The country is well positioned to be a leader in PtX due to its competitive green power prices, its offshore wind potential, and a well-connected intra-Europe transmission system. While Denmark itself does not have a strong industrial sector, its neighboring countries, Germany and the Netherlands, do. Denmark is in a strong position to export hydrogen directly to industrial clusters in these countries.

149 "bp, Iberdrola and Enagás plan to develop the largest green hydrogen project in the region of Valencia," *Iberdrola,* April 28, 2021, https://www.iberdrola.com/press-room/news/detail/iberdrola-enagas-plan-develop-largest-green-hydrogen-project-region-valencia, (accessed August 23, 2021).

150 Denmark has approximately 20 GW of installed offshore wind capacity. See: "A record year: Wind and solar supplied more than half of Denmark's electricity in 2020," *State of Green*, January 11, 2021, https://stateofgreen.com/en/partners/state-of-green/news/a-record-year-wind-and-solar-supplied-more-than-half-of-denmarks-electricity-in-2020/, (accessed August 31, 2021).

151 Denmark Global Climate Action Strategy. See: "A Green and Sustainable World: The Danish Government's long-term strategy for global climate action," *Ministry of Foreign Affairs of Denmark and The Danish Ministry of Climate, Energy and Utilities*, October 2020, https://um.dk/~/media/um/klimastrategi/a_green_and_sustainable_world.pdf?la=en, (accessed August 23, 2021).

National Targets and Ambitions

Hydrogen and PtX present a significant economic opportunity for Denmark. Analyses by various industry groups suggest that PtX will be a cost-effective solution, perhaps as early as 2035. Denmark's unique proposition for the development of green hydrogen is its global leadership in offshore wind development. In 2018, the Danish government agreed on a 2.4 GW target minimum of installed offshore capacity by 2030. In June 2020, the government increased this target to 6 GW to meet its new *Climate Act*, which includes legally binding targets set every five years.[152]

Direct electricity consumption by grid-interactive buildings and vehicles will help balance the grid, but the remaining 30-40 percent of the economy that is difficult to electrify could benefit from sector coupling—or the conversion of renewable electricity into PtX.

Denmark plans to release its national PtX strategy by the end of 2021. Until the plan is released, specific elements of the strategy remain undefined. However, industry groups, such as Hydrogen Denmark and Wind Denmark, and the public and private sector have been contributing suggestions and strategies for Denmark's PtX strategy. In addition, the Danish government has provided support for hydrogen and fuel cell research over the last 20 years and supports the development of fuel cell vehicles with 10 hydrogen refueling stations and tax credits for hydrogen cars. Recent demonstration projects indicate a holistic approach to decarbonization with hydrogen. Rather than a focus on the hard-to-electrify sectors, the demonstration projects indicate an all-the-above approach so that green hydrogen can play an important decarbonization role now. For example, HyBalance is a demonstration project in which the electrolyzers are providing grid services, and the hydrogen is used for transpor-tation and industry. The PEM electrolyzers generate hydrogen when electricity prices are low or when there is a need for system balancing.[153] Another example is the H2RES demonstration project, which has received funding from the Danish Energy Agency. This project will use offshore wind power to produce hydrogen for transportation.[154]

Planned Projects

1. A suite of Danish companies has formed a unique partnership to bring together the demand and supply side of PtX. Together, Copenhagen Airports, Moller-Maersk, DSV Panalpina, DFDS, SAS, and Ørsted are developing an industrial scale facility in Copenhagen that will produce sustainable fuels with offshore wind-powered electrolysis. The project will be developed in three phases, producing 250,000 tons of green fuels by 2030. A 10-MW electrolyzer will be installed in the project's first phase, slated for operation in 2023. The resulting green hydrogen will be used in Movia's city busses and in Panalpina's heavy-duty trucks.

   In Phase II, some offshore wind energy from the purpose-built Ørsted offshore wind farm off of Bornholm will power 250 MW of electrolysis by 2027. The resulting green hydrogen will be combined with CO_2 from carbon capture sources in the Copenhagen

152 The 6 GW will come from three projects: two offshore energy islands connecting 5 GW of offshore wind capacity and one offshore wind project contributing 1 GW of capacity.

153 "What is HyBalance," *HyBalance*, http://hybalance.eu, (accessed August 3, 2021).

154 "H2RES & Green Fuels DK," *EverFuel*, https://www.everfuel.com/projects-archive/h2res-green-fuels-dk-10mw-electrolyser-ptx-activities-and-hydrogen-distribution-facility, (accessed August 3, 2021).

area to produce green methanol and e-kerosene for use by Moller-Maersk cargo ships and SAS airplanes, respectively. By Phase III in 2030, all of Bornholm's offshore wind power will be available and the project would install up to 1.3 GW of electrolyzer capacity. By 2030, the project could eliminate 30 percent of fossil fuel use at Copenhagen Airport.[155]

2. The Green Hydrogen Hub (GHH) is an international consortium of industry leaders and industry groups working together with national governments, including Denmark, to develop the world's first large-scale green hydrogen production project paired with large-scale energy storage.[156] GHH is proposing a 350-MW electrolysis facility powered by excess renewable energy in Jutland, Denmark. The resulting 250 GWh of green hydrogen capacity will be stored in underground salt caverns as 320 MW of compressed air energy storage. The proposed project has two phases:
   - Phase One 2025 Targets
     – Electrolysis capacity 350 MW
     – Hydrogen capacity 200 GWh
     – Hydrogen CAES 320 MW
   - Phase Two 2030 Targets
     – Electrolysis capacity 1000 MW
     – Hydrogen capacity 400 GWh
     – Hydrogen CAES 320 MW

GHH plans to sell the green hydrogen to third parties, presumably for use in the transport and chemical industry sector. It will also use the green hydrogen to secure Denmark's electricity supply by serving as seasonal storage. GHH Denmark estimates that it can eliminate 600,000 tons of CO_2 annually.

CASE STUDY 3
Hydrogen for Germany's Energy Transition

Background
Germany, along with rest of the European Union member states, has committed itself to reducing its greenhouse gas emissions by 2050, based on the targets agreed under the Paris Agreement. Its medium-term target is to cut greenhouse gas emissions by at least 55 percent by 2030, compared to 1990 levels. By 2050, it expects to cut its emissions by 80–95 percent.

155 "Leading Danish companies join forces on an ambitious sustainable fuel project," MAERSK, May 26, 2020, https://www.maersk.com/news/articles/2020/05/26/leading-danish-companies-join-forces-on-an-ambitious-sustainable-fuel-project, (accessed August 17, 2021).

156 "Green Hydrogen Hub Denmark," Green Hydrogen Hub Denmark, https://greenhydrogenhub.dk, (accessed August 3, 2020). 157 "Climate Action Plan 2050," *Federal Ministry for the Environment, Nature Conservation and Nuclear Safety*, November 14, 2016, https://www.bmu.de/en/download/climate-action-plan-2050, (accessed September 3, 2021).

Its Climate Action Plan 2050 sets clear framework conditions to support investments in a new renewable energy future and supports measures to create competitive economic conditions and remain Europe's strongest economy.[157]

In light of these targets and the closure of the country's nuclear and coal-fired power plants, the country is eyeing green hydrogen as an energy gap-filling fuel, especially for the transportation sector and in applications where it is challenging to directly electrify.

National Targets and Ambitions

For Germany to become greenhouse gas neutral and meet its international obligations under the Paris Agreement, it must decarbonize its energy supply. Hydrogen has been cited as a key element in the country's energy transition. In June 2020, the Federal Government of Germany announced its National Hydrogen Strategy (NHS) that commits to establishing 5 GW of hydrogen production capacity by 2030.[158] An additional 5 GW of capacity is to be added, if possible, by 2035 and no later than 2040. The country aims to focus on green hydrogen production, which it considers the only sustainable form of hydrogen, and therefore places equal importance on scaling up the necessary renewable energy capacity. The NHS does, however, concede that blue and turquoise hydrogen will also play a role in the European hydrogen market. The industrial, transport, and heating sectors are the main areas the NHS has targeted for hydrogen application.

Barriers

The barriers to scale-up of a green hydrogen market in Germany are similar to many of the generic barriers affecting most countries, specifically the high cost of green hydrogen and low demand. The national hydrogen strategy identifies fossil fuels prices, and taxes, levies, and surcharges on electricity used for hydrogen production as particular barriers to production of green hydrogen. Fair pricing of fossil fuels that accounts for CO_2 emissions, combined with reduction or exception of electricity charges for green hydrogen production, will be used to overcome this barrier.

Access to low-cost funding and finance for green hydrogen projects is another barrier to uptake of both hydrogen production systems and hydrogen end-use technology, e.g., fuel cells. To enable investment in hydrogen infrastructure the German government is allocating billions in funding for green hydrogen projects.

The pace of new offshore wind installation has slowed in recent years.[159] Germany's offshore wind resource is located in the North Sea and Baltic Sea off the North coast of the country. Grid limitations restricting the ability to transport power from offshore in the North to the demand in South are restricting new offshore wind capacity in the short-to-medium term. Hydrogen could potentially reduce grid connection capacity and enable more offshore wind

157 "Climate Action Plan 2050," Federal Ministry for the Environment, Nature Conservation and Nuclear Safety, November 14, 2016, https://www.bmu.de/en/download/climate-action-plan-2050, (accessed September 3, 2021).

158 "The National Hydrogen Strategy," *Federal Ministry for the Environment, Nature Conservation and Nuclear Safety*, June 10, 2020, https://www.bmwi.de/Redaktion/EN/Publikationen/Energie/the-national-hydrogen-strategy.html, (accessed September 3, 2021).

159 Adrijana Buljan, "Germany Adds (Only) 219 MW of Offshore Wind to Its Grid in 2020," *OffshoreWIND.biz*, January 21, 2021, https://www.offshorewind.biz/2021/01/21/germany-adds-only-219-mw-of-offshore-wind-to-its-grid-in-2020, (accessed September 2, 2021).

to be installed. In the national hydrogen strategy, offshore wind to hydrogen is mentioned specifically with the use of offshore lease areas allocated for hydrogen production being proposed.

Finally, the German Government acknowledges that its own green hydrogen production capacity may not be enough to meet its domestic demand. It therefore will require an international market for green hydrogen, and cooperation on green hydrogen standards amongst its neighbors in Europe, to enable import of green hydrogen. Coordinating standards and regulations relating to use of natural gas infrastructure for hydrogen transportation, such as hydrogen blending limits, will be key to a frictionless European wide market for green hydrogen.

Policy, Technology, and Investments

The construction and operation of a hydrogen production facility currently requires the execution of an authorization procedure pursuant to the *Federal Immission Control Act* (FICA).[160,161] Facilities producing hydrogen from electrolysis are generally exempted from network access charges under the *Renewable Energy Act* (EEG).[162]

The legal framework for hydrogen, however, is not yet comprehensive. The NHS attempts to kick start the development of a regulatory system. The NHS outlines an action plan that contains 38 measures to be implemented between 2020 and 2023 to develop a domestic hydrogen industry. This includes measures that will be made to increase hydrogen production.

The first measure detailed in the NHS to increase hydrogen production is for the federal government to assess the possibility of additional reform of the energy price support component induced by the state, to create a more viable business environment to produce green hydrogen in Germany. In addition, the introduction of carbon pricing for fossil fuels used in transport and the heating sector is an important element to support green hydrogen production.

The government has also examined whether electricity used to produce green hydrogen can be largely exempted from taxes, levies, and surcharges and whether the production of green hydrogen can be exempt from the Erneuerbare-Energien-Gesetz (EEG) surcharge. The *Renewable Energy Sources Act* (RESA) that entered into force in January 2021 stated that the EEG surcharge shall be reduced to zero for all electricity used in the production of green hydrogen. This will only apply to production facilities which become operational before 2030 and will take affect once the Federal Government has defined green hydrogen.

Offshore wind is seen as an attractive renewable technology to use to produce green hydrogen. The offshore wind to hydrogen framework is being developed further to ensure that investments achieve payback. Potential adjustments that are being discussed include the designation of additional areas that can be used for offshore production of hydrogen, investment in necessary infrastructure, and the potential for additional auction rounds.

160 "Production of hydrogen > Centralised (Electrolysis, Steam-Methane reforming, and H2 liquification) > Permitting requirements (include LAP: safety-distances) Germany," *HyLaw*, https://www.hylaw.eu/database/germany/production-of-hydrogen/centralised-electrolysis-steam-methane-reforming-and-h2-liquification/permitting-requirements-include-lap-safety-distances?export=pdf, (accessed August 3, 2021).

161 "Federal Immission Control Act," *HyLaw Online Database*, https://www.hylaw.eu/database/national-legislation/germany/federal-immission-control-act-bundesimmissionsschutzgesetzbimschg, (accessed August 3, 2021).

162 "Law amending the Renewable Energy Sources Act and other energy regulations," *Federal Ministry for Economy and Energy*, January 1, 2021, https://www.bmwi.de/Redaktion/DE/Artikel/Service/gesetz-zur-aenderung-des-eeg-und-weiterer-energierechtlicher-vorschriften.html, (accessed August 23, 2021).

As part of the NHS, the federal government has highlighted measures that will be taken to facilitate demand for hydrogen within the targeted sectors. In the industrial sector, the government intends to incentivize the transition to green hydrogen by providing funding for investments in electrolyzers. In addition, a new pilot program for Carbon Contracts for Difference (CCfD) will be set up. Under the scheme, the government guarantees to support the differential costs between the actual costs of avoiding emissions or a project-related, contractually defined carbon price per avoided quantity of greenhouse gas emissions and the ETS prices for the construction and operation of decarbonization technologies to achieve greenhouse gas neutrality.

To facilitate the use of green hydrogen in each of the identified application areas, the NHS highlights the need to scale up the hydrogen transport and distribution capacity. This includes the expansion of already existing hydrogen infrastructure as well as the rededication of natural gas transport infrastructure that is no longer needed for natural gas transport. The regulation of hydrogen networks is currently under review and aims to ensure hydrogen compatibility with existing or modernized gas infrastructure.

Existing and Planned Projects

AquaVentus

The AquaVentus initiative aims to install 10 GW of electrolysis capacity from offshore wind energy in the North Sea by 2035. This is enough to produce 1 million metric tons of green hydrogen per year. The initiative is supported by 40 partner organizations, including RWE, EnBW, Shell, Equinor, Parkwind, Vattenfall, Siemens, and MHI Vestas.

The German Island of Heligoland will serve at the main hydrogen hub. Offshore wind farms will produce hydrogen at sea before it is transported to Heligoland via pipelines. The hydrogen will then be transported to the mainland via a central collector.

The initiative includes numerous sub-projects along the value chain from hydrogen production to transport. One of the first pilot phases is to install two 14-MW innovative hydrogen wind turbines off the coast of Heligoland. This involves integrating the electrolyzer into the base of the turbine tower. These units will be connected to the grid via a pipeline.

The design of the on-turbine electrolyzer system would see modularized, containerized equipment installed on an extended transition piece platform. The equipment will be installed onshore on the transition piece, reducing installation works offshore. By using high-pressure electrolyzers, it is intended that no additional hydrogen compression is needed to transport hydrogen to shore under 50 km.

A key benefit of this system, and an area for innovation, is the integration of the electrolyzer with the wind turbine power train. A direct DC-DC connection between the wind turbine and electrolyzer could enable the reduction in power electronic equipment required for DC-AC conversion, removal of medium-voltage transformer, and improve overall efficiency of the turbine.

WESTKÜSTE 100

marliesplatvoet/Pixabay

The WESTKÜSTE 100 project aims to research and develop an approach to produce green hydrogen from offshore wind energy and to use the resulting waste heat and oxygen effectively. The project is being delivered by EDF Germany, Holcim Germany, OGE, Ørsted, Raffinerie Heide, Stadtwerke Heide, Thyssenkrupp Industrial Solutions, and Thüga, together with the Heide Region Development Agency and the West Coast University of Applied Sciences.

The project is in the northern German state of Schleswig-Holstein. It received approval from the German Federal Ministry of Economic Affairs and Energy in 2020. Over the next five years, a 30-MW electrolysis plant will be built by a newly formed joint venture between EDF Germany, Ørsted, and Raffinerie Heide and will produce green hydrogen from offshore wind energy. The project's next stage aims to scale the electrolysis plant capacity to 700 MW.

The green hydrogen will be fed into a new hydrogen grid, which will connect to the refinery. In addition, the project will examine whether the oxygen produced during electrolysis can be fed into the combustion process of a local cement plant, which would significantly reduce the plant›s nitrogen oxide emissions. In return, the carbon dioxide generated by the cement plant would be used as a raw material, together with green hydrogen, to produce synthetic hydrocarbons which could be used for aviation fuel. The waste heat produced in the electrolysis process could be used to heat a local business plant.

CASE STUDY 4
Green Hydrogen Demonstration Projects Underway in the UK

Background

In line with commitments made under the Paris Agreement, the United Kingdom has set a target of achieving net-zero emissions by 2050. Its medium-term target is to cut greenhouse gas emissions by at least 68 percent by 2030 and 78 percent by 2035 compared to 1990 levels.[163]

163 "UK enshrines new target in law to slash emissions by 78% by 2035," *Gov.UK*, Press Release, April 2021, https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035, (accessed August 30, 2021).

National Targets and Ambitions

In November 2020, the UK Government released The Ten Point Plan for a Green Industrial Revolution that sets out the plan to accelerate the path to net zero. It commits to developing 5 GW of low-carbon hydrogen production capacity by 2030.[164] However, the UK Government has yet to publish a hydrogen strategy although a full hydrogen strategy from the Government is anticipated in 2021.

The Ten Point Plan's focus on "low-carbon hydrogen" capacity suggests that it may not necessarily be green hydrogen generated from renewable energy. It is anticipated that blue hydrogen will make up most of the planned capacity. In addition, the plan states an ambition to heat an entire town with hydrogen by the end of the decade.

Barriers

For the UK, the cost of green hydrogen, low demand for hydrogen, and lack of a detailed hydrogen strategy are the key barriers to development of a green hydrogen market. Details on how the government intends to meet its 5 GW electrolyzer target are not currently clear. The first barrier which the UK must overcome is this lack of certainty in government policy. In addition to the lack of clear government strategy, cost remains the primary barrier to uptake of green hydrogen.

The UK Government's use of Contracts for Difference has successfully supported cost reduction and deployment of renewable energy generation. Similar market support mechanisms could be used to help support green hydrogen projects and reduce the cost of green hydrogen.

Access to funding for commercial projects, research and development, and manufacturing facilities will be needed to achieve economies of scale, and enable industry learning, which will be required to achieve lower LCOH. Lack of affordable funding for demonstration projects and R&D could be barriers to deployment of green hydrogen production.

Transmission costs are another cost barrier for green hydrogen in the UK. Grid charges increase the cost of green hydrogen produced by grid-connected electrolyzers. Furthermore, existing hydrogen policies, such as the UK's renewable transport fuel obligations (RTFO) scheme do not accommodate hydrogen produced from grid-connected electrolyzers.[165]

These barriers could be overcome by reducing the cost burden on grid-connected electrolyzers by reducing or exempting electrolyzers from grid charges and allowing grid connected electrolyzers with renewable energy PPAs to be included in existing market support mechanisms such as the RTFO.

Finally, new regulations and standards for the safe use of hydrogen and hydrogen/methane blends in existing gas infrastructure, and particularly in domestic environments, will be key to overcoming legislative barriers preventing the wide roll out of hydrogen in existing gas networks.

164 "The ten point plan for a green industrial revolution," *Gov.UK*, November 18, 2020, https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution, (accessed August 30, 2021).

165 "Renewable Transport Fuel Obligation (RTFO) guidance: 2021," *Gov.UK*, January 4, 2021, https://www.gov.uk/government/publications/renewable-transport-fuel-obligation-rtfo-guidance-2021, (accessed August 30, 2021).

Policy, Technology, and Investments

The United Kingdom has seen a lot of investment in hydrogen projects in recent years. The UK government has focused its investment on research and development of technology and on demonstration-scale projects. Recent government activity has included establishing targets for electrolyzer production by 2020 and a focus on business models that could be used to kick-start the hydrogen economy. A summary of policies implemented to date are given below.

The UK Government Low Carbon Hydrogen Supply competition was launched in 2018. Over two phases, £33 million has been invested in identifying and developing low-carbon bulk hydrogen supply solutions. Phase 1 funded feasibility studies to accelerate the development of low-carbon bulk hydrogen supply solutions, while Phase 2 provided funding for demonstration projects. Projects that received Phase 2 funding are currently under development.

The Ten Point Plan for a Green Industrial Revolution published in November 2020 outlines future investments that will be made to support the growth of clean hydrogen over the coming years.[166] This includes a £240 million Net Zero Hydrogen Fund to support the production of new hydrogen production facilities. A total of £81 million has also been committed for pioneering hydrogen heating trials. In addition, the government pledged to bring forward a revenue mechanism in 2021 to attract private sector investment into hydrogen projects.

The Energy White Paper, published in December 2020, provides further clarity on the Ten Point Plan for a Green Industrial Revolution. Hydrogen is included as one of ten priority areas in the Net Zero Innovation Portfolio which will receive £1 billion to accelerate the commercialization of low-carbon technologies. There will also be further investments in energy systems, transport, and industry to increase the application of hydrogen, including £20 million for developing hydrogen-powered vehicles, £120 million to start the delivery of 4,000 zero-emission buses, and £20 million for a Clean Maritime Demonstration Competition to accelerate the decarbonization of the maritime sector.

The Industrial Strategy Challenge will provide public investment of up to £170 million, matched by £261 million from industry. The UK aims to create four low-carbon industrial hubs by 2030 and at least one net-zero emission cluster by 2040. This will fund the development of technologies such as carbon capture and storage and hydrogen fuel switching, which will be deployed and scaled up within the UK's largest industrial clusters.

The UK established the **Hydrogen Advisory Council** in July 2020. It works to identify and promote the actions required to enable the supply of low-carbon hydrogen at scale for use across the energy system. According to the Energy White Paper, the Council is set to publish a national hydrogen strategy in 2021.

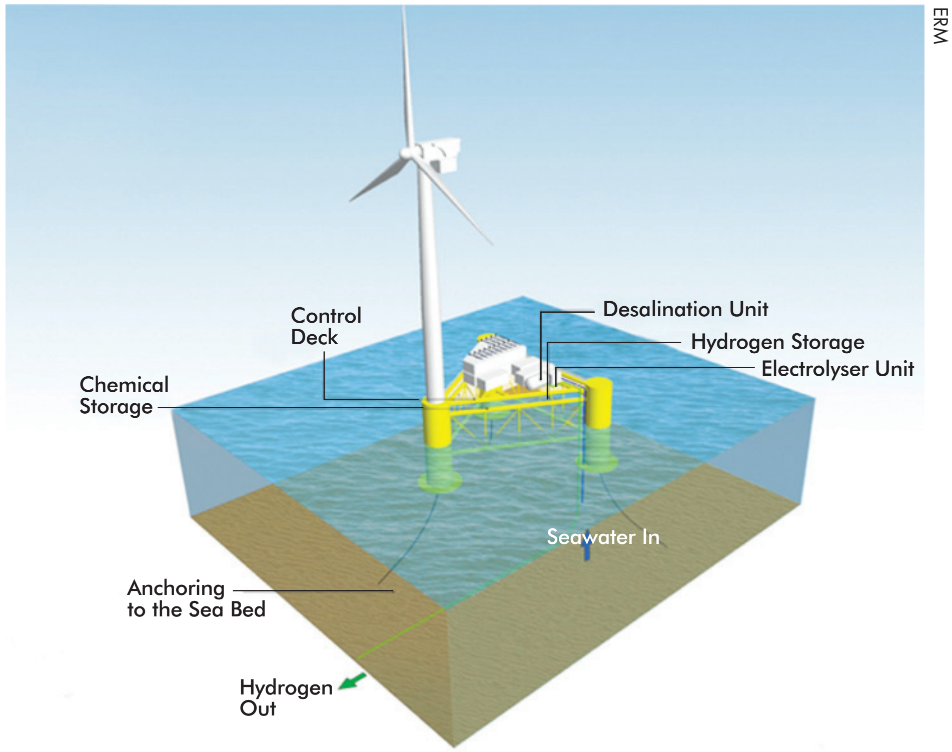
166 "The Ten Point Plan for a Green Industrial Revolution," *Gov.UK*, November 2020, https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution, (accessed September 1, 2021).

167 Topside refers to the platform sitting on top of the floating foundation, which will hold the hydrogen production and storage equipment.

Existing and Planned Project Examples

Dolphyn Project

FIGURE APP-1: **3D schematic of Dolphyn floating wind to hydrogen concept**



The Dolphyn Project aims to use desalinated seawater to produce green hydrogen via electrolysis, in a process powered by floating offshore wind turbines (see **Figure APP-1**). The project is led by Environmental Resources Management (ERM) and is funded by the UK Government's Hydrogen Supply Competition Program.

The design consists of a floating wind turbine with an integrated water treatment unit and PEM electrolyzer. It incorporates its own standby power unit, supplied by hydrogen stored on the facility, and is therefore completely autonomous. Hydrogen produced by the floating platform will be piped to shore.

The project had planned to deploy a 2-MW prototype system at the Kincardine offshore windfarm site 15 km off the coast of Aberdeen by 2024; however, early design works have been so successful that the project will deploy a full-scale demonstration on a 10-MW turbine by 2024. The ultimate aim is to deploy a 4-GW array of floating 10-MW wind turbines with electrolyzers in the North Sea by the early 2030s.

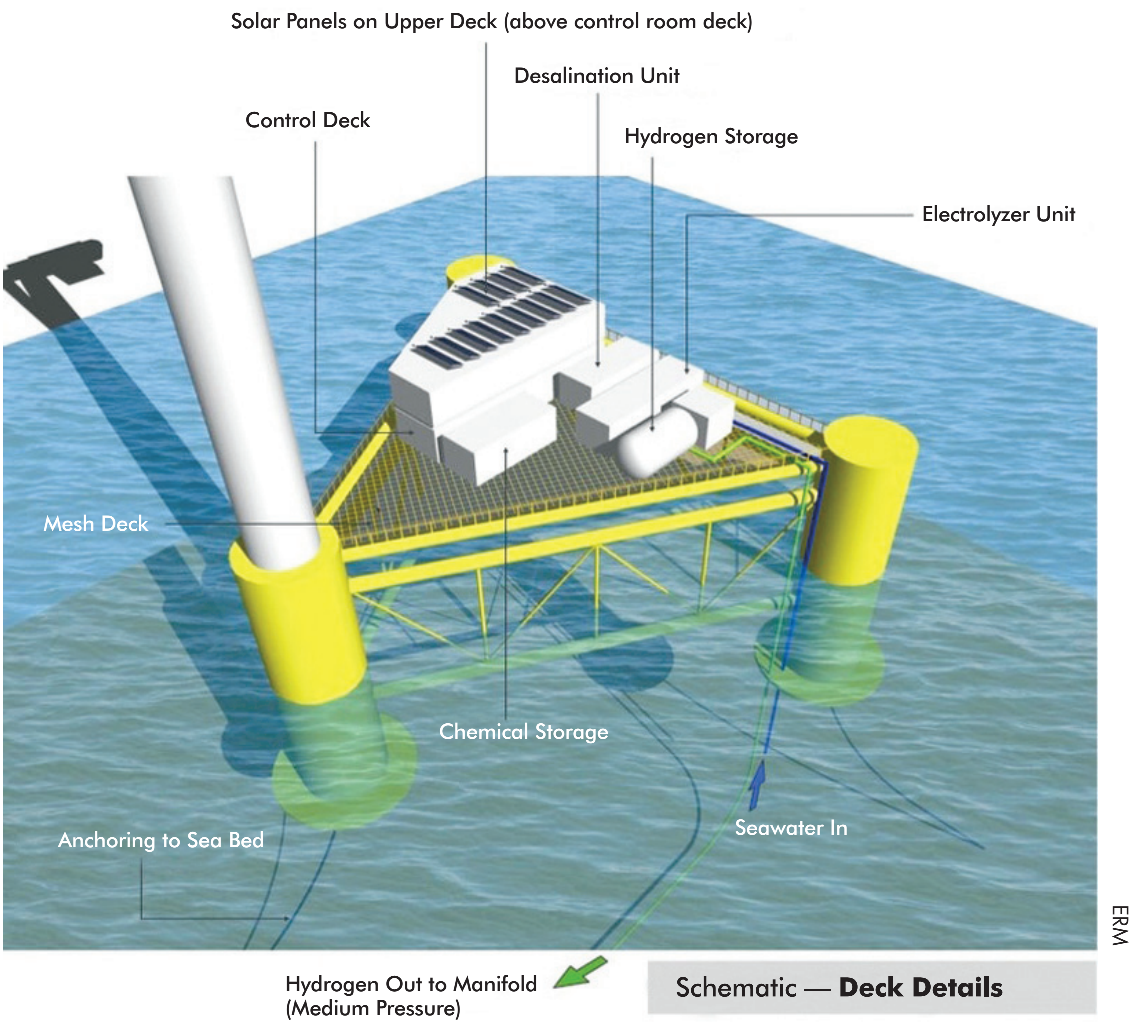
Tracetebel Engie and Principle Power are responsible for the floating sub-structure design, and ODE is responsible for the topsides including the desalination and stand-by power unit.[167] NEL and Doosan are responsible for the electrolyzer design and its integration into the overall system.

The Dolphyn project hopes to demonstrate cost effective hydrogen production from floating wind turbine generators. The results of these project will be key to understanding hydrogen role in reducing the over cost of energy from floating windfarms, which are typically located further from shore and therefore incur higher energy transmission losses and costs.

The illustration (see **Figure APP-2**) below shows a 3D model of the Dolphyn system as well as a closer look at the electrolyzer system located on the topside.[168]

168 "ERM Dolphyn," *ERM*, https://ermdolphyn.erm.com/p/1, (accessed August 3, 2020).

FIGURE APP-2: **Close-up look of hydrogen production equipment on Dolphyn floating wind to hydrogen concept**



Gigastack

The Gigastack project aims to demonstrate the delivery of large volume, low-cost, and zero-carbon hydrogen using gigawatt-scale PEM electrolyzers. A key objective of the project is to identify challenges for industrial-scale green hydrogen use. It is led by ITM Power, in collaboration with Ørsted, Phillips 66, and Element Energy, and is funded the UK Government's Hydrogen Supply Competition Program.

In Phase 1 of the project, which concluded in 2019, ITM Power designed a 5-MW electrolyzer stack that will be used in the development of a 100-MW electrolyzer system. This phase also modelled the production capacity of ITM Power's new electrolyzer factory, identified wind power synergies for hydrogen production, and assessed the business case for hydrogen in target markets.

Phase 2 of the project began in 2020 and involves conducting a Front-End Engineering Design (FEED) study of a 100-MW electrolyzer. The FEED study will detail the actual design of a hydrogen production system. It is anticipated that the system will use electricity from

Ørsted's Hornsea Two offshore wind farm to generate green hydrogen for the Phillips 66 Humber Refinery. In addition, further plans for large scale production of electrolyzers are being developed, and a large electrolyzer is set to be deployed following the conclusion of Phase 2 in 2021.

The increased demand created by the Gigastack project enables the upscaling of electrolyzer manufacturing. Fundamental to achieving low-cost hydrogen is the reduction in electrolyzer costs achieved through economies of scale. ITM power recently commenced production at its new manufacturing facility in Sheffield UK, known as "the giga factory," which has been designed to manufacture 1 GW of electrolyzers per year.[169]

The gigafactory, enabled in part by the Gigastack project and associated funding, demonstrates the job creation potential of the hydrogen industry should governments act to establish and develop local supply chains.

169 "Manufacturing Commences at the ITM Power Gigafactory," ITM Power, January 4, 2021, https://www.itm-power.com/news/manufacturing-commences-at-the-itm-power-gigafactory, (accessed September 9, 2021).

The Clean Energy States Alliance (CESA) is a national, nonprofit coalition of public agencies and organizations working together to advance clean energy. CESA members—mostly state agencies—include many of the most innovative, successful, and influential public funders of clean energy initiatives in the country.

Ørsted US Offshore Wind/Block Island Wind Farm

Clean Energy States Alliance

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Clockwise from upper left: Shutterstock/Soonthorn Wongsaita; Tom Piorkowski; Resonant Energy; Portland General Electric; RE-volv; Bigstockphoto.com/Davidm199